Vanguard Natural Resources, LLC (VNR)

10-K
Annual report pursuant to section 13 and 15(d)
Filed on 03/08/2011
Filed Period 12/31/2010

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2010

Or

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

For the transition period from to .

Commission File Number **001-33756**

Vanguard Natural Resources, LLC

(Exact Name of Registrant as Specified in Its Charter)

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

Telephone Number: (832) 327-2255
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 ☐ No ☒

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

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

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

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

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

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

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

The aggregate market value of Vanguard Natural Resources, LLC common units held by non-affiliates of the registrant as of June 30, 2010 was approximately $397,020,016 based upon the New York Stock Exchange composite transaction closing price.

As of March 1, 2011 29,770,627 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 2011 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, 2010 ("this Annual Report").

Vanguard Natural Resources, LLC

TABLE OF CONTENTS

Forward Looking Statements

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

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

- the volatility of realized oil, natural gas and natural gas liquids prices;
- the potential for additional impairment due to future declines in oil, natural gas and natural gas liquids prices;
- uncertainties about the estimated quantities of oil, natural gas and natural gas liquids 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 oil, natural gas and natural gas liquids reserves;
- our business and financial strategy;
- our drilling locations;
- technology;
- our cash flow, liquidity and financial position;
- the timing and amount of our future production of oil, natural gas and natural gas liquids;
- 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;
- the ability of Encore Energy Partners LP to make distributions to its unitholders and general partner;
- our prospect development and property acquisitions;
- the marketing of oil, natural gas and natural gas liquids;
- competition in the oil, natural gas and natural gas liquids 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 oil and natural gas 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	MMBbls	= million barrels
BOE	= barrel of oil equivalent	MMBOE	= million barrels of oil equivalent
Btu	= British thermal unit	MMBtu	= million British thermal units
Gal	= gallons	MMcf	= million cubic feet
MBbls	= thousand barrels	MMcfe	= million cubic feet of natural gas equivalents
MBOE	= thousand barrels of oil equivalent	NGLs	= natural gas liquids

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

References in this report to (1) “us,” “we,” “our,” “the Company,” “Vanguard” or “VNR” are to Vanguard Natural Resources, LLC and its subsidiaries, including Vanguard Natural Gas, LLC (“VNG”), Trust Energy Company, LLC (“TEC”), VNR Holdings, LLC (“VNRH”), Ariana Energy, LLC (“Ariana Energy”), Vanguard Permian, LLC (“Vanguard Permian”), VNR Finance Corp. (“VNRF”), Encore Energy Partners GP LLC (“ENP GP”), Encore Energy Partners LP (“ENP”), Encore Energy Partners Operating LLC (“OLLC”), Encore Energy Partners Finance Corporation (“ENPF”), Encore Clear Fork Pipeline LLC (“ECFP”) and (2) “Vanguard Predecessor,” “Predecessor,” “our operating subsidiary” or “VNG” are to Vanguard Natural Gas, LLC.

PART I

ITEM 1. BUSINESS

Overview

We are a publicly traded limited liability company focused on the acquisition and development of mature, long-lived oil and natural gas 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 oil and natural gas properties. We own a 100% controlling interest, through certain of our subsidiaries, in properties and oil and natural gas reserves located in four operating areas:

- the Permian Basin in west Texas and New Mexico;
- south Texas;
- the southern portion of the Appalachian Basin, primarily in southeast Kentucky and northeast Tennessee; and
- Mississippi.

In addition, we own an approximate 46.7% aggregate controlling interest through our subsidiary, Encore Energy Partners LP (“ENP”), in properties and oil and natural gas reserves located in four operating areas:

- the Permian Basin in west Texas and New Mexico;
- the Big Horn Basin in Wyoming and Montana;
- the Williston Basin in North Dakota and Montana; and
- the Arkoma Basin in Arkansas and Oklahoma.

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.”

Recent Developments

On December 31, 2010, we completed an acquisition pursuant to a Purchase Agreement with Denbury Resources Inc. (“Denbury”), Encore Partners GP Holdings LLC, Encore Partners LP Holdings LLC and Encore Operating, L.P. (collectively, the “Encore Selling Parties” and, together with Denbury, the “Selling Parties”) to acquire (the “Encore Acquisition” or “Encore”) all of the member interest in ENP GP, the general partner of ENP and 20,924,055 common units representing limited partnership interests in ENP (the “ENP Units”), representing an approximate 46.7% aggregate controlling interest in ENP. As consideration for the purchase, we paid $300.0 million in cash and paid $80.0 million in stock by issuing 3,137,255 VNR common units, at an agreed upon price of $25.50 per unit, valued at the closing price of $29.65 at December 31, 2010.

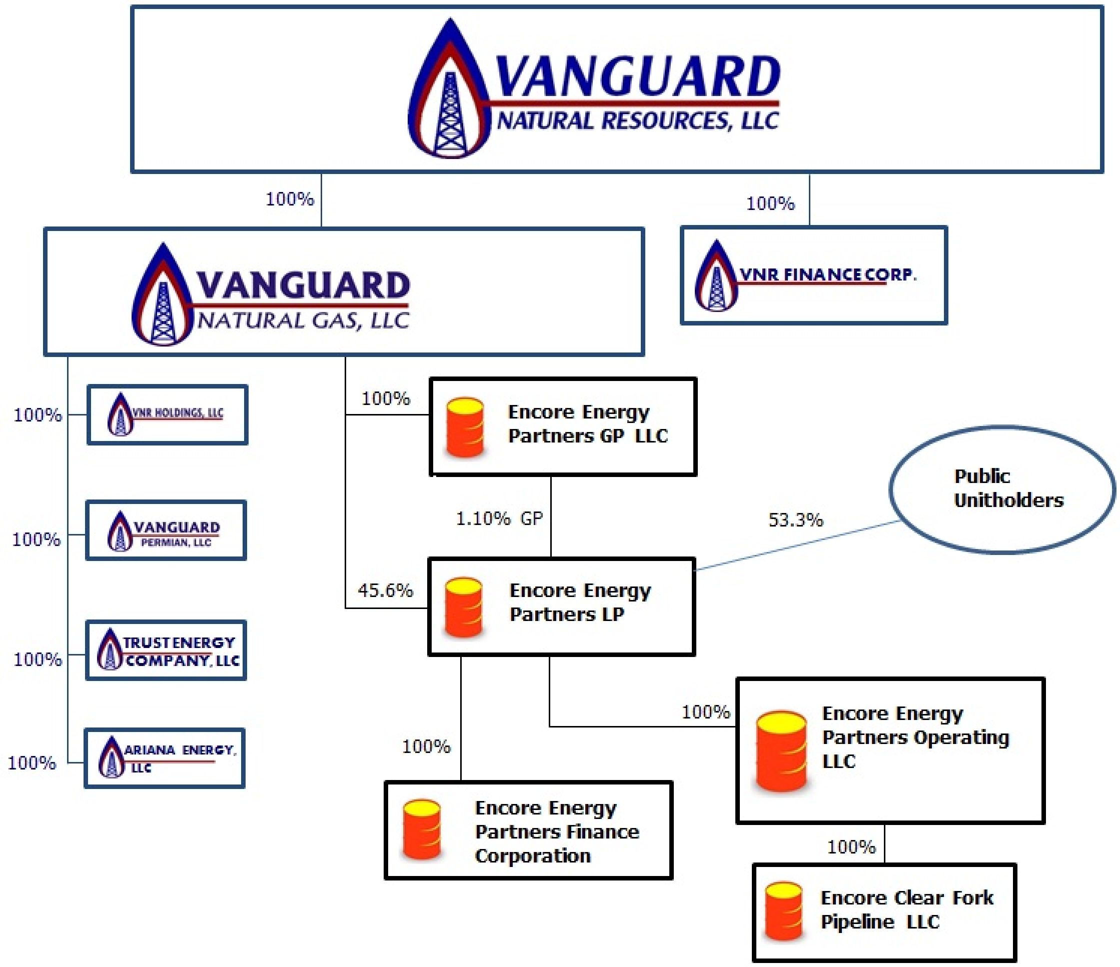
In connection with the closing of the Encore Acquisition, VNG entered into a Second Amended and Restated Administrative Services Agreement, dated December 31, 2010, with ENP, ENP GP, Encore Operating, L.P. (“Encore Operating”), OLLC and Denbury (the “Services Agreement”). The Services Agreement was amended solely to add VNG as a party and provide for VNG to assume the rights and obligations of Encore Operating and Denbury under the previous administrative services agreement going forward.

Pursuant to the Services Agreement, VNG will provide certain general and administrative services to ENP, ENP GP and the OLLC (collectively, the “ENP Group”) in exchange for a quarterly fee of $2.06 per barrel of oil equivalent of the ENP Group’s total net oil and gas production for the most recently-completed quarter, which fee is paid by ENP (the “Administrative Fee”). The Administrative Fee is subject to certain index-related adjustments on an annual basis. ENP also is obligated to reimburse VNG for all third-party expenses it incurs on behalf of the ENP Group. These terms are identical to the terms under which Denbury and Encore Operating provided administrative services to the ENP Group prior to the second amendment and restatement of the Services Agreement.

As the acquisition was completed on December 31, 2010, no results of operations were included in the consolidated statement of operations for the year ended December 31, 2010. The fair value of the assets and liabilities we acquired on December 31, 2010 in the Encore Acquisition and cash flows associated with the transaction were included in the consolidated balance sheet as of December 31, 2010 and the statement of cash flows for the year ended December 31, 2010, respectively. As of December 31, 2010, based on a reserve report prepared by our independent reserve engineers, the properties owned by ENP have estimated reserves of 41.1 MMBOE (21.9 MMBOE attributable to the non-controlling interest), 67% of which is oil and 87% of which is proved developed producing.

Organizational Structure

The following diagram depicts our organizational structure as of March 8, 2011:



Formation and Acquisitions of Oil and Natural Gas Properties

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, was our founding unitholder. As part of the separation, we retained all of our Predecessor's proved producing wells and associated reserves located in Appalachia. 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 oil and natural gas 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 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. As of December 31, 2010, based on a reserve report prepared by our independent reserve engineers, the Appalachia properties have estimated reserves of 7.6 MMBOE, 95% of which is gas and 68% of which is proved developed producing.

On December 21, 2007, we entered in to a Purchase and Sale Agreement with the Apache Corporation for the purchase of certain oil and natural gas properties located in ten separate fields in the Permian Basin of west Texas and southeastern New Mexico, 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. 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), of which we operate 56 gross wells (54 net wells). 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, 2010, based on a reserve report prepared by our independent reserve engineers, these acquired properties have estimated proved reserves of 3.4 MMBOE, 90% 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 oil and natural gas 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 VNR common units. 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 2011 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, 2010, based on a reserve report prepared by our independent reserve engineers, these acquired properties have estimated proved reserves of 2.8 MMBOE, 99% of which is natural gas and natural gas liquids and 60% of which is proved developed producing.

On July 17, 2009, we entered into a Purchase and Sale Agreement with Segundo to acquire certain oil and natural gas properties located in the Sun TSH Field in La Salle County, Texas for $52.3 million, referred to as the “Sun TSH acquisition.” The acquisition had a July 1, 2009 effective date and was completed on August 17, 2009 for an adjusted purchase price of $50.5 million. An affiliate of Lewis operates all of the wells acquired in this transaction. This acquisition was funded with borrowings under our reserve-based credit facility and proceeds from the Company’s public equity offering of 3.9 million common units completed on August 17, 2009. At closing, we assumed natural gas puts and swaps based on NYMEX pricing for approximately 61% of the estimated gas production from then-existing producing wells in the acquired properties for the period beginning August of 2009 through December of 2010, which had a fair value of $4.1 million on the closing date. In addition, concurrent with the execution of the Purchase and Sale Agreement, we entered into a collar for certain volumes in 2010 and a series of collars for a substantial portion of the expected gas production for 2011 at prices above the then-current market price with a total cost to the Company of $3.1 million, which was financed through deferred premiums. As of December 31, 2010, based on a reserve report prepared by our independent reserve engineers, these acquired properties have estimated proved reserves of 6.1 MMBOE, 98% of which is natural gas and natural gas liquids and 60% of which 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 oil and natural gas properties located in Ward County, Texas in the Permian Basin from private sellers, referred to as the “Ward County acquisition.” This transaction had an effective date of October 1, 2009 and was closed on December 2, 2009 for $55.0 million. This acquisition was initially funded with borrowings under our reserve-based credit facility with borrowings being reduced by $40.3 million shortly thereafter with the proceeds from a 2.3 million common unit offering. We operate all but one of the ten wells acquired in this transaction. As of December 31, 2010, based on a reserve report prepared by our independent reserve engineers, these acquired properties have estimated proved reserves of 3.7 MMBOE, 74% of which is oil and 59% of which is proved developed producing.

On April 30, 2010, we entered into a definitive agreement with a private seller for the acquisition of certain oil and natural gas properties located in Mississippi, Texas and New Mexico. We refer to this acquisition as the “Parker Creek acquisition.” The purchase price for said assets was $113.1 million with an effective date of May 1, 2010. We completed this acquisition on May 20, 2010. The adjusted purchase price of $114.3 million considered final purchase price adjustments of approximately $1.2 million. The purchase price was funded from the approximate $71.5 million in net proceeds from our May 2010 equity offering and with borrowings under the Company’s existing reserve-based credit facility. As of December 31, 2010, based on a reserve report prepared by our independent reserve engineers, these acquired properties had estimated proved reserves of 4.3 MMBOE, 97% of which is oil and 37% of which is proved developed producing.

Proved Reserves

Based on reserve reports prepared by our independent reserve engineers, DeGolyer and MacNaughton, or “D&M,” our total estimated proved reserves at December 31, 2010 were 69.3 MMBOE, of which approximately 55% were oil reserves and 80% were classified as proved developed. At December 31, 2010, we owned working interests in 4,895 gross (2,270 net) productive wells. Our estimated proved reserves and productive wells at December 31, 2010 include those proved reserves and productive wells that we acquired in connection with the Encore Acquisition and are subject to a 53.3% non-controlling interest in ENP. Our average net production for the year ended December 31, 2010 was 4,721 BOE per day. Our average net production did not include any production from properties acquired in connection with the Encore Acquisition. We also have a 40% working interest in approximately 109,291 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 9%, or 2.4 MMBOE, of our estimated proved reserves as of December 31, 2010 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. 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, VNR owns working interests ranging from 30-100% in approximately 15,890 undeveloped acres surrounding our existing wells. Additionally, ENP owns working interests ranging from 8-77% in approximately 15,372 undeveloped acres surrounding their existing wells.

Our average proved reserves-to-production ratio, or average reserve life, is approximately 14 years based on our total proved reserves as of December 31, 2010 including proved reserves associated with properties acquired in the Encore Acquisition and the combined production of VNR and ENP for 2010. Our proved reserves associated with properties acquired in the Encore Acquisition and the production of ENP are subject to a 53.3% non-controlling interest in ENP. As of December 31, 2010, we have identified 460 proved undeveloped drilling locations and over 205 other drilling locations on our leasehold acreage.

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 oil and natural gas assets with a focus on maintaining cash flow levels;
- Replace reserves either through the development of our extensive inventory of proved undeveloped locations or make accretive acquisitions of oil and natural gas 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 oil and natural gas prices.

Properties

As of December 31, 2010, we own a 100% controlling interests, through certain of our subsidiaries, in oil and gas properties located in the Permian Basin, South Texas, Appalachian Basin, and Mississippi. We own an approximate 46.7% aggregate controlling interest in ENP’s properties located in the Permian Basin, Big Horn Basin, Williston Basin and the Arkoma Basin. The following table presents the production for the year ended December 31, 2010 and the estimated proved reserves for each operating area:

	Operator	2010 Net	Net Estimated
VNR Properties:			
Permian Basin	Vanguard Permian, LLC	498.2	7,345
South Texas:			
Sun TSH Field	Lewis Petroleum	302.5	6,094
Other	Lewis Petroleum	170.0	2,838
Appalachian Basin	Vinland Energy Operations, LLC	602.6	7,599
Mississippi	Roundtree and Associates	149.7	4,336
ENP Properties:			
Permian Basin	OLLC	•	16,367(2)
Big Horn Basin	OLLC	•	18,334(2)
Williston Basin	OLLC	•	4,957(2)
Arkoma Basin	OLLC	•	1,416(2)

(1) No production results are included for properties acquired on December 31, 2010 related to the Encore Acquisition.
(2) Includes the non-controlling interest of approximately 53.3% as of December 31, 2010.

Following is a description of our properties by operating areas:

Permian Basin Properties

The Permian Basin is one of the largest and most prolific oil and natural gas producing basins in the United States. The Permian Basin extends over 100,000 square miles in West Texas and southeast New Mexico and has produced over 24 billion Bbls of oil since its discovery in 1921. The Permian Basin is characterized by oil and natural gas fields with long production histories and multiple producing formations.

During 2010, our Permian Basin operations produced approximately 498.2 MBOE. These properties accounted for approximately 23,712 MBOE or 34% of our total estimated proved reserves at year end, of which 19,562 MBOE were proved developed and 4,150 MBOE were proved undeveloped. This includes 16,367 MBOE acquired in the Encore Acquisition of which 78% were proved developed. As of December 31, 2010, our Permian Basin properties consisted of 79,910 gross (54,415 net) acres.

South Texas Properties

Most of our South Texas properties are operated by Lewis Petroleum and are located in two fields, Gold River North Field and Sun TSH Field, located in Webb and LaSalle Counties, Texas. Vanguard’s working interest ranges from 45% to 100%. Most of the production is high BTU gas that is produced from the Olmos and Escondido sand formations from a depth ranging from 4,700 feet to 7,800 feet.

During 2010, the South Texas properties produced approximately 472.5 MBOE, of which 42% was oil, condensate and NGLs. These properties accounted for approximately 8,932 MBOE or 13% of our total estimated proved reserves at year end, of which 5,667 MBOE were proved developed and 3,265 MBOE were proved undeveloped. As of December 31, 2010, our South Texas properties consisted of 21,020 gross (14,267 net) acres.

Appalachian Basin Properties

Most of our Appalachia properties are operated by Vinland and are located in southeastern Kentucky and northeastern Tennessee. The working interest ranges from 40% to 100% for most of Vanguard’s approximate 1,025 wells. Most of the production is high BTU gas that produces primarily from the Maxon, Big Lime and Devonian Shale from a depth ranging from approximately 1,500 feet to 4,500 feet.

During 2010, the Appalachia properties produced approximately 602.6 MBOE, of which 81% was gas. These properties accounted for approximately 7,599 MBOE or 11% of our total estimated proved reserves at year end, of which 5,164 MBOE were proved developed and 2,434 MBOE were proved undeveloped. As of December 31, 2010, our Appalachian Basin properties consisted of 130,191 gross (65,559 net) acres.

Mississippi Properties

On May 20, 2010, we acquired our interest in properties located in the Mississippi Salt Basin. Most of our Mississippi properties are operated by Roundtree and Associates. Most of the production comes from the Parker Creek Field in Jones County, Mississippi, where our working interest is approximately 53%. Also in 2010, we purchased a license for 10 square miles of 3-D seismic data for the development of Parker Creek Field. Most of the production is oil that produces from the Hosston from a depth ranging from approximately 13,000 feet to 15,000 feet.

From May 20, 2010 through year end, the properties produced approximately 149.7 MBOE, of which 99% was oil. These properties accounted for approximately 4,336 MBOE or 6% of our total estimated proved reserves at year end, of which 2,405 MBOE were proved developed and 1,931 MBOE were proved undeveloped. As of December 31, 2010, our Mississippi properties consisted of 2,560 gross (1,963 net) acres.

Big Horn Basin Properties

On December 31, 2010, we acquired an approximate 46.7% aggregate controlling interest in 24,512 gross and 20,400 net acres in the Big Horn Basin of northwestern Wyoming and south central Montana including the Elk Basin and Gooseberry fields through our subsidiary ENP. We also acquired and took over operatorship of (1) the Elk Basin natural gas processing plant near Powell, Wyoming, (2) the Clearfork crude oil pipeline extending from the South Elk Basin field to the Elk Basin field in Wyoming, (3) the Wildhorse natural gas gathering system that transports low sulfur natural gas from the Elk Basin and South Elk Basin fields to the Elk Basin natural gas processing plant, and (4) a small natural gas gathering system that transports high sulfur natural gas from the Elk Basin field to the Elk Basin natural gas processing facility.

The Big Horn Basin is characterized by oil and natural gas fields with long production histories and multiple producing formations. The Big Horn Basin is a prolific basin and has produced over 1.8 billion Bbls of oil since its discovery in 1906.

ENP's properties in the Elk Basin area are located in the Elk Basin field, Northwest Elk Basin field, and the South Elk Basin field. The Elk Basin assets had estimated proved reserves at December 31, 2010 of 18.3 MMBOE, of which 17.0 MMBOE were proved developed and 1.3 MMBOE were proved undeveloped. ENP's properties in the Elk Basin area include 17,075 gross acres (13,349 net) located in Park County, Wyoming and Carbon County, Montana. ENP operates all properties in the Elk Basin area. The major producing horizons in these fields are the Embar-Tensleep, Madison, Frontier, and Big Horn formations as discussed below.

Embar-Tensleep Formation. Production in the Embar-Tensleep formation is being enhanced through a tertiary recovery technique involving effluent gas, or flue gas, from a natural gas processing facility located in the Elk Basin field. From 1949 to 1974, flue gas was injected into the Embar-Tensleep formation to increase pressure and improve production of resident hydrocarbons. Flue gas injection was re-established in 1998, and pressure monitoring wells indicate that the reservoir pressure continues to increase. ENP's wells in the Embar-Tensleep formation of the Elk Basin field are drilled to a depth of 4,200 to 5,400 feet. ENP holds an average 62% working interest and an average 56% net revenue interest in these wells. At December 31, 2010, the Embar-Tensleep formation had estimated total proved reserves of 5.4 MMBOE, all of which were oil and 95% of which were proved developed.

Madison Formation. Production in the Madison formation is being enhanced through a waterflood. We believe that we can enhance production in the Madison formation by, among other things, reestablishing optimal injection and producing well patterns. The wells in the Madison formation of the Elk Basin field are drilled to a depth of 4,800 to 5,800 feet. ENP holds an average 67% working interest and an average 61% net revenue interest in these wells. The Madison formation had estimated total proved reserves at December 31, 2010 of 7.1 MMBOE, of which 99% were oil and 85% of which were proved developed.

Frontier Formation. The Frontier formation is being produced through primary recovery techniques. The wells in the Frontier formation of the Elk Basin field are typically drilled to a depth of 1,600 to 2,900 feet. ENP holds an average 77% working interest and an average 68% net revenue interest in the wells in the Frontier formation. The Frontier formation had estimated total proved reserves at December 31, 2010 of 577 MBOE, 72% of which were oil and all of which were proved developed.

ENP also operates wells in the Northwest Elk Basin field and South Elk Basin field. ENP holds an average 65% working interest and an average 68 % net revenue interest in the wells in these fields. The Northwest Elk Basin field and South Elk Basin field had estimated total proved reserves at December 31, 2010 of 477 MBOE, 65% of which were oil and all of which were proved developed.

The Gooseberry field is made up of two waterflood units in the Big Horn Basin. The field is located 60 miles south of Elk Basin in Wyoming and consists of 26 active producing wells. Gooseberry is an active waterflood project. The wells in the Gooseberry field are completed at 9,000 feet of depth from the Phosphoria and Tensleep formations. ENP holds all working interest and an average 90% net revenue interest in the wells in the Gooseberry field. The Gooseberry field had estimated proved reserves at December 31, 2010 of 4.5 MMBOE, all of which were oil and all of which were proved developed. ENP's properties in the Gooseberry field include 7,437 gross acres (7,051 net) located in Park County and Hot Springs, Wyoming.

ENP operates and owns a 62% interest in the Elk Basin natural gas processing plant near Powell, Wyoming, which was first placed into operation in the 1940s. ExxonMobil Corporation owns a 34% interest in the Elk Basin natural gas processing plant, and other parties own the remaining 4% interest. This plant is a refrigeration natural gas processing plant that receives natural gas supplies through a natural gas gathering system from fields in the Elk Basin and South Elk Basin fields.

ENP owns and operates one crude oil pipeline system and two natural gas gathering pipeline systems in the Big Horn Basin. The Clearfork pipeline is regulated by the FERC and transports approximately 4,369 Bbls/day of crude oil from the Elk Basin field to a pipeline operated by Marathon Oil Corporation for further delivery to other markets. Most of the crude oil transported by the Clearfork pipeline is eventually sold to refineries in Billings, Montana. The Clearfork pipeline receives crude oil from various interconnections with local gathering systems. The Wildhorse pipeline system is an approximately 12-mile natural gas gathering system that transports approximately 1.3 MMcf/day of low-sulfur natural gas from the Elk Basin and South Elk Basin fields to the Elk Basin natural gas processing plant. The natural gas transported by the Wildhorse gathering system is sold into the WBI Pipeline. ENP also owns a small natural gas gathering system that transports approximately 14.0 MMcf/day of high sulfur natural gas from the Elk Basin field to the Elk Basin natural gas processing plant.

Williston Basin Properties

ENP's Williston Basin properties include: Horse Creek, Charlson Madison Unit, Elk, Cedar Creek MT, Lookout Butte East, Pine, Beaver Creek, Buffalo Wallow, Buford, Crane, Charlie Creek, Dickinson, Elm Coulee, Lone Butte, Lonetree Creek, Missouri Ridge, Tracy Mountain, Tract Mountain Fryburg, Treetop, Trenton, and Whiskey Joe. ENP's Williston Basin properties had estimated proved reserves at December 31, 2010 of 5.0 MMBOE, of which 4.5 MMBOE were proved developed and 0.5 MMBOE were proved undeveloped.

Arkoma Basin Properties

ENP's Arkoma properties include royalty interests and non-operated working interest properties. The royalty interest properties include interests in over 1,700 wells in Arkansas, Texas, and Oklahoma as well as 10,300 unleased mineral acres. The non-operated working interest properties include interests in over 100 producing wells in the Chismville field. At December 31, 2010, the properties had total proved reserves of approximately 1.4 MMBOE, all of which were proved developed and 87% of which were natural gas.

Oil, Natural Gas and Natural Gas Liquids 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. 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, 2010, 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 $0.14 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, 2010, our average realized natural gas prices in Appalachia (before hedging), represented a $1.15 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, 2010, 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 $0.41 per MMBtu.

In South Texas, our natural gas production has a high Btu content and requires 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 2010, we received the average WTI price less $12.79 per barrel in Appalachia and the average WTI price less $4.43 per barrel in the Permian Basin.

We enter into derivative transactions in the form of hedging arrangements to reduce the impact of oil and natural gas price volatility on our cash flow from operations. Currently, we use fixed-price swaps, swaptions, put options and NYMEX collars to hedge oil and natural gas prices. By removing the price volatility from a significant portion of our oil and natural gas production, we have mitigated for a period of time, but not eliminated, the potential effects of fluctuation in oil and natural gas 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."

Oil, Natural Gas and Natural Gas Liquids Data

Estimated Proved Reserves

The following table presents our estimated net proved oil, natural gas and natural gas liquids reserves and the present value of the estimated proved reserves at December 31, 2010, based on reserve reports prepared by D&M. Copies of their summary reports are included as exhibits to this Annual Report. Our estimated proved reserves and productive wells at December 31, 2010 include those proved reserves that we acquired in connection with the Encore Acquisition and are subject to a 53.3% non-controlling interest in ENP. 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 oil, natural gas and natural gas liquids reserves.

	As of December 31, 2010		
	VNR	**ENP (1)**	**Total**
Reserve Data:			
Estimated net proved reserves:			
Crude oil (MBbls)	10,678	27,443	38,121
Natural gas (Bcf)	79.4	74.5	153.9
Natural gas liquids (MBbls)	4,298	1,210	5,508
Total (MMBOE)	28.2	41.1	69.3
Proved developed (MMBOE)	18.7	37.0	55.7
Proved undeveloped (MMBOE)	9.5	4.1	13.6
Proved developed reserves as % of total proved reserves	66%	90%	80%
Standardized Measure (in millions) (2)	$ 414.9	$ 703.5	$ 1,118.4
Representative Oil and Natural Gas Prices (3):			
Oil•WTI per Bbl	$ 79.40	$ 79.43	
Natural gas•Henry Hub per MMBtu	$ 4.38	$ 4.45	

(1) Includes the non-controlling interest of approximately 53.3% as of December 31, 2010.

(2) 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."

(3) Oil and natural gas prices are based on spot prices per Bbl and MMBtu, respectively, calculated using the 12-month unweighted average of first-day-of-the-month price (the "12-month average price") for January through December 2010, with these representative prices adjusted by field for quality, transportation fees and regional price differentials to arrive at the appropriate net price.

The following tables set forth certain information with respect to our estimated proved reserves by operating area as of December 31, 2010 based on estimates made in a reserve report prepared by D&M.

Operating Area	Estimated Proved Developed Reserve Quantities				Estimated Proved Undeveloped Reserve Quantities				Estimated Proved Reserve Quantities
	Natural Gas (Bcf)	Oil (MMBbls)	NGLs (MMBbls)	Total (MMBOE)	Natural Gas (Bcf)	Oil (MMBbls)	NGLs (MMBbls)	Total (MMBOE)	Total (MMBOE)
VNR Properties:									
Permian Basin	3.1	4.6	0.4	5.5	1.3	1.4	0.3	1.9	7.4
South Texas	19.4	0.1	2.3	5.6	11.2	0.1	1.3	3.3	8.9
Appalachian Basin	28.9	0.3	•	5.2	14.6	•	•	2.4	7.6
Mississippi	0.9	2.3	•	2.4	•	1.9	•	1.9	4.3
ENP Properties: (2)									
Permian Basin	54.8	5.0	•	14.1	7.3	1.1	•	2.3	16.4
Big Horn Basin	2.2	15.5	1.2	17.0	•	1.3	•	1.3	18.3
Williston Basin	2.7	4.0	•	4.5	0.2	0.5	•	0.5	5.0
Arkoma Basin	7.3	0.2	•	1.4	•	•	•	•	1.4
Total	119.3	32.0	3.9	55.7	34.6	6.3	1.6	13.6	69.3

Operating Area	PV10 Value (1) Developed	Undeveloped	Total
	(in millions)		
VNR Properties:			
Permian Basin	$ 121.4	$ 25.3	$ 146.7
South Texas	59.9	20.8	80.7
Appalachian Basin	54.0	(2.7)	51.3
Mississippi	77.2	59.0	136.2
ENP Properties: (2)			
Permian Basin	159.4	17.7	177.1
Big Horn Basin	387.2	26.1	413.3
Williston Basin	88.4	6.2	94.6
Arkoma Basin	18.5	•	18.5
Total	$ 966.0	$ 152.4	$ 1,118.4

(1) PV10 is not a measure of financial or operating performance under GAAP, nor should it be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP. However, for Vanguard, PV10 is equal to the standardized measure of discounted future net cash flows under GAAP because the Company is not a tax paying entity. For our presentation of the standardized measure of discounted future net cash flows, please see "Supplemental Oil and Natural Gas Information" in the Notes to the Consolidated Financial Statements in Part II, Item 8 in this Annual Report on Form 10-K.
(2) Includes the non-controlling interest of approximately 53.3% as of December 31, 2010.

The data in the above tables represent estimates only. Oil, natural gas and natural gas liquids and oil reserve engineering is inherently a subjective process of estimating underground accumulations of oil, natural gas and natural gas liquids 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 oil, natural gas and natural gas liquids 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 reserve engineers to prepare a reserve and economic evaluation of properties that we are considering purchasing. Neither the reserve engineers 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 2010, we paid Netherland, Sewell & Associates, Inc. and DeGolyer and MacNaughton approximately $50,000 and $25,000, respectively, for all reserve and economic evaluations.

Proved Undeveloped Reserves

Our proved undeveloped reserves at December 31, 2010, as estimated by our independent petroleum engineers, were 13.6 MMBOE, consisting of 6.3 million barrels of oil, 34.6 MMcf of natural gas and 1.6 million barrels of natural gas liquids. Our proved undeveloped reserves increased by 5.9 MMBOE during the year ended December 31, 2010, due to the acquisition of 4.1 MMBOE and 1.9 MMBOE total proved undeveloped reserves in connection with the Encore and Parker Creek acquisitions, respectively, which was offset by the development of 1.5% of our total proved undeveloped reserves booked as of December 31, 2009 through the drilling of two gross (1.5 net) well at an aggregate capital cost of approximately $7.8 million. The proved undeveloped reserves that we acquired in connection with the Encore Acquisition are subject to a 53.3% non-controlling interest in ENP.

None of our proved undeveloped reserves at December 31, 2010 have remained undeveloped for more than five years since the date of initial booking as proved undeveloped reserves. At December 31, 2010, there are 6 locations with 0.3 MMBOE 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.

At December 31, 2010, all of our leases are held by production, with the exception of 955 acres in Ward County, Texas that will expire in September of 2011. We anticipate that we will drill in this acreage prior to the lease expiration date.

Qualifications of Technical Persons and Internal Controls over Reserves Estimation Process

Our proved reserve information as of December 31, 2010 included in this Annual Report was estimated by our independent petroleum engineers, D&M, in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information promulgated by the Society of Petroleum Engineers and definitions and guidelines established by the SEC.

Our Senior Vice President of Operations, Britt Pence, is the person primarily responsible for overseeing the preparation of our internal reserve estimates and for the coordination of the third-party reserve reports provided by D&M. Mr. Pence has over 27 years of experience and is a graduate of Texas A&M University with a Bachelor of Science degree in Petroleum Engineering. He is a member of the Society of Petroleum Engineers. Prior to joining us in 2007, Mr. Pence held engineering and managerial positions with Anadarko Petroleum Corporation, Greenhill Petroleum Company and Mobil Oil Corporation.

Within D&M, the technical person primarily responsible for preparing the estimates set forth in the D&M report letter is Mr. Paul J. Szatkowski. Mr. Szatkowski is a Senior Vice President with D&M and has over 35 years of experience in oil and gas reservoir studies and reserves evaluations. He graduated from Texas A&M University in 1974 with a Bachelor of Science Degree in Petroleum Engineering and is a member of the International Society of Petroleum Engineers and the American Association of Petroleum Geologists. Mr. Szatkowski meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and is proficient in applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

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 D&M in their reserves estimation process. In the fourth quarter, our technical team met on a regular basis with representatives of D&M to review properties and discuss methods and assumptions used in D&M’s preparation of the year-end reserves estimates. All field and reserve technical information, which is updated annually, is assessed for validity when D&M hold technical meetings with our internal staff of petroleum engineers, operations and land personnel to discuss field performance and to validate future development plans. While we have no formal committee specifically designated to review reserves reporting and the reserves estimation process, the D&M reserve report is reviewed by our senior management and internal technical staff.

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, D&M 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.

Production and Price History

The following table sets forth information regarding net production of oil, natural gas and natural gas liquids and certain price and cost information for each of the periods indicated. No production results are included for properties acquired on December 31, 2010 related to the Encore Acquisition.

	Net Production			Average Realized Sales Prices (3)			Production Cost (4)
	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, 2010 (1)							
Sun TSH Field	40	2,586	15,025	$ 75.74	$ 7.59	$ 1.14	$ 5.77
Other	1,830	11,086	9,086	$ 76.54	$ 10.45	$ 0.99	$ 11.77
Total	1,870	13,672	24,111	$ 76.53	$ 9.91	$ 1.09	$ 10.72
Year Ended December 31, 2009 (2)							
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 (5)							
Total other	715	11,450	3,271	$ 85.69	$ 10.49	$ 1.18	$ 11.24

(1) Average daily production for 2010 calculated based on 365 days including production for the Parker Creek acquisition from the closing date of this acquisition.

(2) 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.

(3) 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.

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

(5) 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, 2010 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
VNR Properties:						
Permian Basin	•	•	877	130	877	130
South Texas	208	204	•	•	208	204
Appalachian Basin	1,025	886	•	•	1,025	886
Mississippi	•	•	20	8	20	8
ENP Properties:						
Permian Basin	562	274	1,542	379	2,104	653
Big Horn Basin	41	30	353	272	394	302
Williston Basin	23	6	106	70	129	76
Arkoma Basin	129	10	9	1	138	11
Total	1,988	1,410	2,907	860	4,895	2,270

Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2010 relating to our leasehold acreage.

	Developed Acreage (1)		Undeveloped Acreage (2)		Total Acreage	
	Gross (3)	Net (4)	Gross (3)	Net (4)	Gross (3)	Net (4)
VNR Properties:						
Permian Basin	12,907	8,944	3,350	2,760	16,257	11,704
South Texas	8,480	8,262	12,540	6,005	21,020	14,267
Appalachian Basin	20,900	18,966	109,291	46,593	130,191	65,559
Mississippi	2,560	963	•	•	2,560	963
ENP Properties: (5)						
Permian Basin	59,617	37,612	4,036	5,099	63,653	42,711
Big Horn Basin	23,392	19,327	1,120	1,073	24,512	20,400
Williston Basin	39,870	31,689	9,859	6,595	49,729	38,284
Arkoma Basin	3,192	411	357	84	3,549	495
Total	170,918	126,174	140,553	68,209	311,471	194,383

(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 oil or natural gas, 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.

(5) Includes the non-controlling interest of approximately 53.3% as of December 31, 2010.

Drilling Activity

In Appalachia, most of our wells are drilled to depths ranging from 2,000 feet to 4,500 feet. 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 and 2010, we and our operating partner, Vinland, decided not to drill any new gas wells until natural gas prices improve. However, during 2010 we drilled nine oil wells and completed four wells targeting oil zones less than 3,000 feet. At year end 2010, five of these wells were awaiting completion, expected in 2011.We plan to drill an additional 12 oil wells in 2011.

In the Permian Basin, we drilled one Vanguard operated horizontal oil well in the 3rd Bone Spring sand in Ward County, Texas. This well was drilled to a vertical depth of approximately 11,400 feet with an approximate 4,000 feet lateral and completed with a 7 stage fracture stimulation job. The well's initial production was over 500 barrels of oil equivalent per day. There were five proved undeveloped and two probable horizontal Bone Spring wells remaining to drill at year end 2010. In 2011, we plan to drill two horizontal Bone Spring wells.

In South Texas, most of our wells are drilled to depths ranging from 5,500 feet to 7,800 feet. Most of the reserves are produced from the Olmos gas sands. In 2010, we participated in the drilling of one horizontal Olmos well in Webb County, Texas with a 45% working interest. The well initially produced 1.2 MMcfd. In 2011, we plan to drill four vertical Olmos and Escondido gas wells in La Salle County, Texas with a 50% working interest.

In Mississippi, we participated in the drilling of one 13,886 foot Hosston oil well in the Parker Creek Field with an approximate 53% working interest. The well initially produced over 100 barrels of oil per day. In 2011, we plan to drill two Hosston oil wells in the Parker Creek Field with an approximate 53% working interest.

During 2011, we intend to concentrate our drilling on low risk, development opportunities with the majority of drilling capital focused on oil wells. Excluding any potential acquisitions, we currently anticipate a capital budget for 2011 of between $27.0 million and $28.5 million, which includes anticipated expenditures for VNR and our 46.7% aggregate controlling interest in ENP. VNR's stand alone capital budget is expected to be between $17.9 and $18.7 million and will largely include oil focused drilling in our Bone Springs play in the Permian Basin and the Hosston formation in Mississippi. The remaining $9.1 to $9.8 million represents our net interest in capital spending for Encore which will focus primarily on oil drilling in the Big Horn Basin and a variety of recompletion projects in the Permian Basin.

The following table sets forth information with respect to wells completed during the years ended December 31, 2010, 2009 and 2008. 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. The following table does not include any drilling activity associated with the Encore Acquisition completed on December 31, 2010.

	Year Ended December 31,		
	2010	2009	2008
Gross wells:			
Productive	8	1	86
Dry	•	•	1
Total	8	1	87
Net Development wells:			
Productive	4.6	0.45	38
Dry	•	•	1
Total	4.6	0.45	39
Net Exploratory wells:			
Productive	•	•	•
Dry	•	•	•
Total	•	•	•

Operations

Principal Customers

For the year ended December 31, 2010, sales of oil, natural gas and natural gas liquids to Seminole Energy Services, Plains Marketing L.P., Shell Trading (US) Company, Osram Sylvania, Inc., and Occidental Energy Marketing, Inc. accounted for approximately 20%, 19%, 11%, 5% and 4%, respectively, of our oil, natural gas and natural gas liquids revenues. Our top five purchasers during the year ended December 31, 2010, therefore accounted for 59% of our total revenues. To the extent these and other customers reduce the volumes of oil, natural gas and natural gas liquids 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.

Delivery Commitments and Marketing Arrangements

Our oil and natural gas production is principally sold to marketers, processors, refiners, and other purchasers that have access to nearby pipeline, processing, and gathering facilities. In areas where there is no practical access to pipelines, oil is trucked to central storage facilities where it is aggregated and sold to various markets and downstream purchasers. Our production sales agreements generally contain customary terms and conditions for the oil and natural gas industry, provide for sales based on prevailing market prices in the area, and generally are month-to-month or have terms of one year or less. As of December 31, 2010, we did not have any ongoing delivery commitments of fixed and determinable quantities of oil or natural gas.

We generally sell our natural gas production from our operated properties on the spot market or under market-sensitive, short-term agreements with purchasers, including the marketing affiliates of intrastate and interstate pipelines, independent marketing companies, gas processing companies, and other purchasers who have the ability to pay the highest price for the natural gas production and move the natural gas under the most efficient and effective transportation agreements. Because all of our natural gas production from our operated properties is sold under market-priced agreements, we are positioned to take advantage of future increases in natural gas prices, but we are also subject to any future price declines. We do not market our own natural gas on our non-operated Permian Basin properties, but receive our share of revenues from the operator.

The marketing of our Big Horn heavy sour crude oil production is through our Clearfork pipeline, which transports the crude oil to local and other refiners through connections to other interstate pipelines. Our Big Horn sweet crude oil production is transported from the field by a third party trucking company that delivers the crude oil to a centralized facility connected to a common carrier pipeline with delivery points accessible to local refiners in the Salt Lake City, Utah and Guernsey, Wyoming market centers. We sell oil production from our operated Permian Basin at the wellhead to third party gathering and marketing companies. Any restrictions on the available capacity to transport oil through any of the above mentioned pipelines, or any other pipelines, or any interruption in refining throughput capacity could have a material adverse effect on our production volumes and the prices we receive for our production.

Price Risk and Interest Rate Management Activities

We enter into derivative contracts with respect to a portion of our projected oil and natural gas 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. In addition, we sell calls or provide options to counterparties under swaption agreements to extend the swaps into subsequent years. 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 oil and natural gas 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 tables summarize commodity derivative contracts in place at December 31, 2010:

	Year 2011	Year 2012	Year 2013	Year 2014
Gas Positions:				
Fixed Price Swaps:				
VNG				
Notional Volume (MMBtu)	3,328,312	•	•	•
Fixed Price ($/MMBtu)	$ 7.83	$ •	$ •	$ •
ENP				
Notional Volume (MMBtu)	3,723,730	3,367,932	2,993,000	•
Fixed Price ($/MMBtu)	$ 6.06	$ 5.75	$ 5.10	$ •
Consolidated				
Notional Volume (MMBtu)	7,052,042	3,367,932	2,993,000	•
Fixed Price ($/MMBtu)	$ 6.89	$ 5.75	$ 5.10	$ •
Collars:				
VNG				
Notional Volume (MMBtu)	1,933,500	•	•	•
Floor Price ($/MMBtu)	$ 7.34	$ •	$ •	$ •
Ceiling Price ($/MMBtu)	$ 8.44	$ •	$ •	$ •
Puts:				
ENP				
Notional Volume (MMBtu)	1,240,270	328,668	•	•
Fixed Price ($/MMBtu)	$ 6.31	$ 6.76	$ •	$ •
Total Gas Positions:				
VNG				
Notional Volume (MMBtu)	5,261,812	•	•	•
ENP				
Notional Volume (MMBtu)	4,964,000	3,696,600	2,993,000	•
Consolidated				
Notional Volume (MMBtu)	10,225,812	3,696,600	2,993,000	•

	Year 2011	Year 2012	Year 2013	Year 2014
Oil Positions:				
Fixed Price Swaps:				
VNG				
Notional Volume (Bbls)	443,250	347,700	296,400	209,875
Fixed Price ($/Bbl)	$ 87.94	$ 90.03	$ 89.84	$ 94.37
ENP				
Notional Volume (Bbls)	523,775	947,940	1,295,750	1,168,000
Fixed Price ($/Bbl)	$ 79.48	$ 82.05	$ 88.95	$ 88.95
Consolidated				
Notional Volume (Bbls)	967,025	1,295,640	1,592,150	1,377,875
Fixed Price ($/Bbl)	$ 83.36	$ 84.19	$ 89.11	$ 89.78
Collars:				
VNG				
Notional Volume (Bbls)	•	45,750	45,625	•
Floor Price ($/Bbl)	$ •	$ 80.00	$ 80.00	$ •
Ceiling Price ($/Bbl)	$ •	$ 100.25	$ 100.25	$ •
ENP				
Notional Volume (Bbls)	525,600	274,500	•	•
Floor Price ($/Bbl)	$ 73.06	$ 68.33	$ •	$ •
Ceiling Price ($/Bbl)	$ 95.41	$ 81.12	$ •	$ •
Consolidated				
Notional Volume Bbls)	525,600	320,250	45,625	•
Floor Price ($/Bbl)	$ 73.06	$ 70.00	$ 80.00	$ •
Ceiling Price ($/Bbl)	$ 95.41	$ 83.85	$ 100.25	$ •
Puts:				
ENP				
Notional Volume (Bbls)	803,000	552,660	•	•
Floor Price ($/Bbls)	$ 74.82	$ 65.83	$ •	$ •
Total Oil Positions:				
VNG				
Notional Volume (Bbls)	443,250	393,450	342,025	209,875
ENP				
Notional Volume (Bbls)	1,852,375	1,775,100	1,295,750	1,168,000
Consolidated				
Notional Volume (Bbls)	2,295,625	2,168,550	1,637,775	1,377,875

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

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

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, 2010 (in thousands):

		Notional Amount	Fixed Libor Rates
Period:			
VNG			
January 1, 2011 to March 31, 2011	$	20,000	2.08%
January 1, 2011 to December 10, 2012	$	20,000	3.35%
January 1, 2011 to January 31, 2013	$	20,000	2.38%
January 1, 2011 to January 31, 2013	$	20,000	2.66%
August 6, 2012 to August 6, 2014	$	25,000	2.09%
August 6, 2012 to August 5, 2015 (1)	$	30,000	2.25%
ENP			
January 1, 2011 to January 31, 2011	$	50,000	3.16%
January 1, 2011 to January 31, 2011	$	25,000	2.97%
January 1, 2011 to January 31, 2011	$	25,000	2.96%
January 1, 2011 to March 31, 2012	$	50,000	2.42%

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

Counterparty Risk

At December 31, 2010, 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):

		Current Assets		Current Liabilities		Long-Term Assets		Long-Term Liabilities		Total Amount Due From/(Owed To) Counterparty at December 31, 2010
Citibank, N.A. (A+)	$	5,197	$	•	$	•	$	(441)	$	4,756
Wells Fargo Bank N.A./ Wachovia Bank, N.A. (AA)		182		(438)		2,001		(5,435)		(3,690)
BNP Paribas (AA)		10,992		(7,530)		919		(10,257)		(5,876)
The Bank of Nova Scotia (AA-)		1,325		(478)		•		(4,768)		(3,921)
BBVA Compass (A)		•		(142)		•		(253)		(395)
Credit Agricole (AA-)		4,391		(3,695)		1,912		(4,604)		(1,996)
Royal Bank of Canada (AA-)		2,028		(302)		1,297		(9,050)		(6,027)
Bank of America (A+)		•		(1,216)		•		(226)		(1,442)
Total	$	24,115	$	(13,801)	$	6,129	$	(35,034)	$	(18,591)

In order to mitigate the credit risk of financial instruments, we enter into master netting agreements with our counterparties. The master netting agreement is a standardized, bilateral contract between a given counterparty and us. Instead of treating each financial transaction between the counterparty and us separately, the master netting agreement enables the counterparty and us to aggregate all financial trades and treat them as a single agreement. This arrangement is intended to benefit us in two ways: (1) default by a counterparty under one financial trade can trigger rights to terminate all financial trades with such counterparty; and (2) netting of settlement amounts reduces our credit exposure to a given counterparty in the event of close-out.

Competition

The oil and natural gas 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 oil and natural gas 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 oil and natural gas producing properties, undeveloped leases and drilling rights, and we cannot assure unitholders that we will be able to compete satisfactorily when attempting to make further acquisitions.

Title to Properties

As is customary in the oil and natural gas 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 oil and natural gas 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 oil and natural gas properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas 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 oil and natural gas 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.

Natural Gas Gathering

ENP owns and operates a network of natural gas gathering systems in the Big Horn Basin area of operation. These systems gather and transport their natural gas and a small amount of third-party natural gas to larger gathering systems and intrastate, interstate, and local distribution pipelines. Their network of natural gas gathering systems permits them to transport production from their wells with fewer interruptions and also minimizes any delays associated with a gathering company extending its lines to their wells. Their ownership and control of these lines enables them to:

- realize faster connection of newly drilled wells to the existing system;
- control pipeline operating pressures and capacity to maximize their production;
- control compression costs and fuel use;
- maintain system integrity;
- control the monthly nominations on the receiving pipelines to prevent imbalances and penalties; and
- track sales volumes and receipts closely to assure all production values are realized.

The gas gathering systems were operated for ENP by Encore Operating during 2010 pursuant to an administrative services agreement. During 2011, VNG will operate their gas gathering systems pursuant to the Services Agreement.

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 and as a result, we generally perform the majority of our drilling in these areas 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, oil is typically in higher demand in the summer for its use in road construction and natural gas is in higher demand in the winter for heating. 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, Health and Safety Matters

General. Our business involving the acquisition and development of oil and natural gas properties is subject to extensive and stringent federal, state and local laws and regulations governing the discharge of materials into the environment, conservation and environmental protection, and occupational health and safety. These operations are subject to the same environmental, health and safety laws and regulations as other similarly situated companies in the oil and natural gas 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 and performance of costly remedial measures to mitigate or prevent pollution from historical and ongoing operations, such as pit closure and plugging of abandoned wells;
- 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;
- impose specific health and safety criteria addressing worker protection;
- 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.

Failure to comply with these laws and regulations may result in assessment of administrative, civil and criminal penalties, imposition of removal or remedial obligations, and the issuance of orders enjoining some or all of our operations deemed in non-compliance. Moreover, these laws and regulations may restrict our ability to produce oil, natural gas and natural gas liquids by, among other things, limiting production 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 oil and natural gas 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 oil and natural gas 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 existing or newly adopted environmental laws and regulations may impact our properties or the operations. For the year ended December 31, 2010, 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 2011 or that will otherwise have a material impact on our financial position or results of operations.

The following is a summary of the more significant existing environmental and occupational health and safety laws to which our business operations are subject and for which compliance may have a material impact on our operations as well as the oil and natural gas exploration and production industry in general.

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. 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 oil and natural gas 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 certain classes of 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 found 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 oil and natural gas 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 these substances, wastes and hydrocarbons have been taken for treatment or 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.

ENP's Elk Basin assets include a natural gas processing plant. Previous environmental investigations of the Elk Basin natural gas processing plant indicate historical soil and groundwater contamination by hydrocarbons and the presence of asbestos-containing material at the site. Although the environmental investigations did not identify an immediate need for remediation of the suspected historical hydrocarbon contamination or abatement of the asbestos, the extent of the hydrocarbon contamination is not known and, therefore, the potential liability for remediating this contamination may be significant. In the event we ceased operating the gas plant, the cost of decommissioning it and addressing the previously identified environmental conditions and other conditions, such as waste disposal, could be significant. We do not anticipate ceasing operations at the Elk Basin natural gas processing plant in the near future nor a need to commence remedial activities at this time. However, a regulatory agency could require us to investigate and remediate any hydrocarbon contamination even while the gas plant remains in operation. As of December 31, 2010, we have recorded $10.1 million as future abandonment liability for the estimated cost for decommissioning the Elk Basin natural gas processing plant. Due to the significant uncertainty associated with the known and unknown environmental liabilities at the gas plant, our estimate of the future abandonment liability includes a large reserve. Our estimates of the future abandonment liability and compliance costs are subject to change and the actual cost of these items could vary significantly from those estimates.

Water. 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 oil and natural gas 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.

The primary federal law for oil spill liability is the Oil Pollution Act (“OPA”), which addresses three principal areas of oil pollution•prevention, containment, and cleanup. OPA applies to vessels, offshore facilities, and onshore facilities, including exploration and production facilities that may affect waters of the United States. Under OPA, responsible parties, including owners and operators of onshore facilities, may be held strictly liable for oil cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations, including shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. However, the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the federal Safe Drinking Water Act’s Underground Injection Program. While the EPA has yet to take any action enforce or implement this newly asserted regulatory authority, industry groups have filed suit challenging the EPA’s recent decision. At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with results of the study anticipated to be available by late 2012, and a committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. In addition, legislation was proposed in the recently ended session of Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process, and such legislation could be introduced in the current session of Congress. Also, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances or otherwise require the public disclose of chemicals used in the hydraulic fracturing process. For example, Wyoming, where we pursue development of natural gas, has adopted legislation requiring drilling operators conducting hydraulic fracturing activities in that state to publicly disclose the chemical used in the hydraulic fracturing process. If new federal or state laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could increase our costs of compliance and delay or reduce demand for the oil and natural gas we produce.

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.

Activities on Federal Lands. Oil and natural gas 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 increase the cost of developing oil and natural gas projects.

In response to findings that emissions of carbon dioxide, methane, and other greenhouse gases, or “GHGs,” present an endangerment to public health and the environment because emissions of such gasses are contributing to the warming of the earth’s atmosphere and other climate changes, the U.S. Environmental Protection Agency, or “EPA,” has adopted regulations under existing provisions of the federal Clean Air Act that require a reduction in emissions of GHGs from motor vehicles effective January 2, 2011 and thereby triggered construction and operating permit review for GHG emissions from certain stationary sources. The EPA has published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration, or “PSD,” and Title V permitting programs, pursuant to which these permitting programs have been “tailored” to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet “best available control technology” standards, which will be established by the states or, in some instances, by the EPA on a case-by-case basis. The EPA’s rules relating to emissions of GHGs from large stationary sources of emissions are currently subject to a number of legal challenges but the federal courts have thus far declined to issue any injunctions to prevent EPA from implementing or requiring state environmental agencies to implement the rules. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities. With regards to the monitoring and reporting of GHGs, on November 30, 2010, the EPA published a final rule expanding its existing GHG emissions reporting rule published in October 2009 to include onshore and offshore oil and natural gas production and onshore oil and natural gas processing, transmission, storage, and distribution activities, which may include certain of our operations, beginning in 2012 for emissions occurring in 2011.

In addition, Congress has from time to time considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. These allowances would be expected to escalate significantly in cost over time. The adoption of legislation or regulations that requires reporting of GHGs or otherwise limits emissions of GHGs from our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas that we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our operations.

Occupational Safety and Health. We are subject to the requirements of the federal Occupational Safety and Health Act, as amended, or "OSHA," and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, EPA community right-to-know regulations under the Title III of CERCLA and similar state statutes require that we maintain and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governmental authorities and citizens.

Other Regulation of the Oil and Natural Gas Industry

The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and natural gas 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 oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas 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.

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 oil and natural gas 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 oil and natural gas 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 oil, natural gas and natural gas liquids 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 oil, natural gas and natural gas liquids. 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.

State Regulation. The various states regulate the drilling for, and the production, gathering and sale of, oil, natural gas and natural gas liquids, including imposing severance and other production related taxes and requirements for obtaining drilling permits. Reduced rates or credits may apply to certain types of wells and production methods. For example, currently, a severance tax on oil, natural gas and natural gas liquids 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 oil and natural gas 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 oil, natural gas and natural gas liquids 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.

In addition to production taxes, Texas and Montana each impose ad valorem taxes on oil and natural gas properties and production equipment. Wyoming and New Mexico impose an ad valorem tax on the gross value of oil and natural gas production in lieu of an ad valorem tax on the underlying oil and natural gas properties. Wyoming also imposes an ad valorem tax on production equipment. North Dakota imposes an ad valorem tax on gross oil and natural gas production in lieu of an ad valorem tax on the underlying oil and gas leases or on production equipment used on oil and gas leases.

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.

Federal, State, or Native American Leases. Our operations on federal, state, or Native American oil and natural gas leases are subject to numerous restrictions, including nondiscrimination statutes. Such operations must be conducted pursuant to certain on-site security regulations and other permits and authorizations issued by the Federal Bureau of Land Management, Minerals Management Service, and other agencies.

Operating Hazards and Insurance

The oil and natural gas business involves a variety of operating risks, including fires, explosions, blowouts, environmental hazards, and other potential events that can adversely affect our ability to conduct operations and cause us to incur substantial losses. Such losses could reduce or eliminate the funds available for exploration, exploitation, or leasehold acquisitions or result in loss of properties.

In accordance with industry practice, we maintain insurance against some, but not all, potential risks and losses. We do not carry business interruption insurance. We may not obtain insurance for certain risks if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable at a reasonable cost. If a significant accident or other event occurs that is not fully covered by insurance, it could adversely affect us.

Employees

As of March 1, 2011, we had 83 full time employees. 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

Our principal executive office is located at 5847 San Felipe, Suite 3000, Houston, Texas 77057. Our main telephone number is (832) 327-2255.

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 oil, natural gas and natural gas liquids we produce;
- the price at which we are able to sell our oil, natural gas and natural gas liquids production;
- the level of our operating costs;
- the level and success of VNR’s and ENP’s price risk management activities;
- 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 performance of ENP and its subsidiaries and ENP's ability to make cash distributions to us, which is dependent upon the results of operations, cash flows and financial condition of ENP;
- 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 distributions, in which event the market price of our common units may decline substantially.

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, borrowings under our reserve-based credit facility and other financing arrangements; 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 and other financing arrangements when they expire.

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 financing arrangements have 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 oil, natural gas and natural gas liquids reserves, which will take into account the prevailing oil, natural gas and natural gas liquids 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.

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 financing arrangements. 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 oil and natural gas 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.

ENP's revolving credit facility also contains operating and financial restrictions and covenants which limit the amounts that ENP can borrow to a borrowing base amount, determined by the lenders in their sole discretion. Outstanding borrowings in excess of the borrowing base are required to be repaid immediately, or are required to pledge other oil and gas properties as additional collateral.

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 periods prior to December 31, 2009 difficult and could limit our ability to book additional proved undeveloped reserves in the future.

Our reserve report presents estimates of our proved reserves as of December 31, 2010, 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 12-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 VNR's reserves as of December 31, 2010 was based on the 12-month average price of $4.38 per MMBtu for natural gas and $ 79.40 per barrel of crude oil, as compared to $3.87 per MMBtu for natural gas and $61.04 per Bbl for oil as of December 31, 2009. As a result of these changes, direct comparisons to our previously-reported reserves prior to December 31, 2009 may be more difficult.

The new SEC rules also state 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. 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 reviewed our and other 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, 2010 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.

Oil, natural gas and natural gas liquids prices are volatile. A decline in oil, natural gas and natural gas liquids 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 oil and natural gas properties depend primarily upon the prices we receive for our oil, natural gas and natural gas liquids production and the prices prevailing from time to time for oil, natural gas and natural gas liquids. 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 oil, natural gas and natural gas liquids 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.

Oil, natural gas and natural gas liquids prices historically have been volatile and are likely to continue to be volatile in the future, especially given current geopolitical and economic conditions. For example, the crude oil spot price per barrel for the period between January 1, 2010 and December 31, 2010 ranged from a high of $91.48 to a low of $64.78 and the NYMEX natural gas spot price per MMBtu for the period January 1, 2010 to December 31, 2010 ranged from a high of $6.01 to a low of $3.29. As of March 1, 2011, the crude oil spot price per barrel was $99.63 and the NYMEX natural gas spot price per MMBtu was $3.87. 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 oil, natural gas and natural gas liquids are subject to a variety of factors, including:

- the level of consumer demand for oil, natural gas and natural gas liquids;
- the domestic and foreign supply of oil, natural gas and natural gas liquids;
- commodity processing, gathering and transportation availability, and the availability of refining capacity;
- the price and level of imports of foreign crude oil, natural gas and natural gas liquids;
- 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 oil, natural gas and natural gas liquids prices would not only reduce our revenue, but could reduce the amount of oil, natural gas and natural gas liquids that we can produce economically and, as a result, could have a material adverse effect on our financial condition, results of operations and reserves. 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 oil and natural gas 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.

Lower oil, natural gas and natural gas liquids 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 oil and natural gas properties. Under this method, we capitalize the cost to acquire, explore for, and develop oil and natural gas properties. Under full cost accounting rules, the net capitalized costs of proved oil and natural gas 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 oil and natural gas 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 could have a material adverse effect on our results of operations in the period incurred and would reduce our members’ equity.

The risk that we will be required to write down the carrying value of our oil and natural gas properties increases when oil and gas prices are low or volatile. In addition, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties and goodwill if we experience substantial downward adjustments to our estimated proved reserves, or if estimated future operating or development costs increase. For example, oil, natural gas and natural gas liquids 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 additional 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 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 2011, we do not anticipate an impairment at March 31, 2011.

Our acquisition activities will subject us to certain risks.

Since 2008, we have expanded our operations through acquisitions. 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.

A portion of our assets are our partnership interests in ENP and, therefore, our cash flow is dependent upon the ability of ENP to make distributions in respect of those partnership interests.

A portion of our assets are our partnership interests in ENP. As a result, our cash flow depends on the performance of ENP and its' subsidiaries and ENP's ability to make cash distributions to us, which is dependent on the results of operations, cash flows and financial condition of ENP. The amount of cash that ENP can distribute to its partners, including us, each quarter depends upon the amount of cash it generates from its operations, which will fluctuate from quarter to quarter and will depend on, among other things:

- the price of oil and natural gas;
- the weather in ENP's operating areas;
- the level of competition from other oil and natural gas companies;
- the level of ENP's operating costs;
- prevailing economic conditions; and
- the level and success of ENP's price risk management activities.

In addition, the actual amount of cash that ENP will have available for distribution will also depend on other factors, such as:

- the level of capital expenditures it makes;
- its ability to make borrowings under its revolving credit facility to pay distributions;
- its cost of acquisitions and sources of cash used to fund its acquisitions;
- debt service requirements and restrictions on distributions contained in its revolving credit facility or future debt agreements;
- fluctuations in its working capital needs;
- its general and administrative expenses;
- its cash settlements of commodity derivative contracts;
- the timing and collectability of its receivables; and
- the amount of cash reserves established by the board of directors of ENP's general partner for the proper conduct of its business.

We do not have complete control over many of these factors. Accordingly, we cannot guarantee that ENP will have sufficient available cash to pay a specific level of cash distributions to its partners.

Furthermore, unitholders should be aware that the amount of cash that ENP has available for distribution depends primarily upon cash flow, including cash flow from financial reserves and working capital borrowings, and is not solely a function of profitability, which will be affected by non-cash items. As a result, ENP may make cash distributions during periods when it records net losses and may not make cash distributions during periods when it records net income.

The consolidated debt level and debt agreements of ENP and its subsidiaries may limit the distributions we receive from ENP and our future financial and operating flexibility.

As of December 31, 2010, ENP had approximately $234.0 million of outstanding borrowings and $141.0 million of capacity under its revolving credit facility. ENP's level of indebtedness affects its operations in several ways, including, among other things:

- ENP's ability to obtain additional financing, if necessary, for working capital, capital expenditures;
- acquisitions, or other purposes may not be available on favorable terms, if at all;
- covenants contained in future debt arrangements may require ENP to meet financial tests that may affect its flexibility in planning for and reacting to changes in its business, including possible acquisition opportunities;
- ENP will need a substantial portion of its cash flow to make principal and interest payments on its indebtedness, reducing the funds that would otherwise be available for operations, future business opportunities, and distributions to unitholders; and
- ENP's debt level will make it more vulnerable to competitive pressures, or a downturn in our business or the economy in general, than its competitors with less debt.

ENP is not prohibited from competing with us.

Neither our partnership agreement nor the partnership agreement of ENP prohibit ENP from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, ENP may acquire, construct or dispose of any assets in the future without any obligation to offer us the opportunity to purchase or construct any of those assets.

ENP may issue additional common units, which may increase the risk that ENP will not have sufficient available cash to maintain or increase its per unit distribution level.

The partnership agreement of ENP allows ENP to issue an unlimited number of additional limited partner interests. The issuance of additional common units or other equity securities by ENP will have the following effects:

- unitholders' current proportionate ownership interest in ENP will decrease;
- the amount of cash available for distribution on each common unit or partnership security may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding common unit may be diminished; and
- the market price of ENP's common units may decline.

The payment of distributions on any additional units issued by ENP may increase the risk that ENP may not have sufficient cash available to maintain or increase its per unit distribution level, which in turn may impact the available cash that we have to meet our obligations.

We rely on Vinland, an affiliate of our founding 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 founding unitholder, under which we rely on Vinland to operate all of our existing producing wells and coordinate our development drilling program in Appalachia. Under the agreements, Vinland will also advise and consult with us regarding all aspects of our production and development operations in Appalachia and provide us with administrative support services as necessary or useful for the operation of our business. If Vinland fails to or inadequately performs these functions, our operations in Appalachia will be disrupted and our costs could increase or our reserves may not be developed or properly developed, reducing our future levels of production and our cash from operations, which could affect our ability to make cash distributions to our unitholders.

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

Under the terms of our operating agreement with Lewis Petroleum, 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.

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 oil or natural gas in an exact way. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and/or natural gas and assumptions concerning future oil and natural gas 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 oil and natural gas 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 oil, natural gas and natural gas liquids 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, 2010 would decrease from $1.1 billion to $954.0 million, based on price sensitivity generated from an internal evaluation. Our standardized measure is calculated using unhedged oil and natural gas 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 oil, natural gas and natural gas liquids 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 proved 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 oil and natural gas properties will be affected by factors such as:

- the volume, pricing and duration of our oil and natural gas hedging contracts;
- supply of and demand for oil, natural gas and natural gas liquids;
- actual prices we receive for oil, natural gas and natural gas liquids;
- our actual operating costs in producing oil, natural gas and natural gas liquids;
- 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 oil and natural gas 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 oil and natural gas 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 oil and natural gas 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 oil, natural gas and natural gas liquids 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 oil, natural gas and natural gas liquids we are able to produce from existing wells;
- the prices at which our oil, natural gas and natural gas liquids 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 oil, natural gas and natural gas liquids 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 oil, natural gas and natural gas liquids 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 oil, natural gas and natural gas liquids we produce and could reduce our revenues and cash available for distribution.

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

The Federal Trade Commission (“FTC”), Federal Regulatory Commission (“FERC”) and the Commodities Futures Trading Commission (“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 oil, natural gas and natural gas liquids 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 and regulatory initiatives restricting emissions of greenhouse gases may adversely affect our operations, our cost structure, or the demand for oil and natural gas.

In response to findings that emissions of carbon dioxide, methane, and other greenhouse gases, or “GHGs,” present an endangerment to public health and the environment because emissions of such gasses are contributing to the warming of the earth’s atmosphere and other climate changes, the U.S. Environmental Protection Agency, or “EPA,” has adopted regulations under existing provisions of the federal Clean Air Act that require a reduction in emissions of GHGs from motor vehicles effective January 2, 2011 and thereby triggered construction and operating permit review for GHG emissions from certain stationary sources. The EPA has published its final rule to address the permitting of GHG emissions from stationary sources under Prevention of Significant Deterioration, (“PSD”) and Title V permitting programs, pursuant to which these permitting programs have been “tailored” to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet “best available control technology” standards, which will be established by the states or, in some instances, by the EPA on a case-by-case basis. The EPA’s rules relating to emissions of GHGs from large stationary sources of emissions are currently subject to a number of legal challenges but the federal courts have thus far declined to issue any injunctions to prevent EPA from implementing or requiring state environmental agencies to implement the rules. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities. With regards to the monitoring and reporting of GHGs, on November 30, 2010, the EPA published a final rule expanding its existing GHG emissions reporting rule published in October 2009 to include onshore and offshore oil and natural gas production and onshore oil and natural gas processing, transmission, storage, and distribution activities, which may include certain of our operations, beginning in 2012 for emissions occurring in 2011.

In addition, Congress has from time to time actively considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. These allowances would be expected to escalate significantly in cost over time. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise limits emissions of GHGs from our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas that we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our provision of services.

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

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

We depend on certain key customers for sales of our oil, natural gas and natural gas liquids. To the extent these and other customers reduce the volumes of oil, natural gas and natural gas liquids 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, 2010, sales of oil, natural gas and natural gas liquids to Seminole Energy Services, Plains Marketing L.P., Shell Trading (US) Company, Osram Sylvania, Inc., and Occidental Energy Marketing, Inc. accounted for approximately 20%, 19%, 11%, 5% and 4%, respectively, of our oil, natural gas and natural gas liquids revenues. Our top five purchasers during the year ended December 31, 2010, therefore accounted for 59% of our total revenues. To the extent these and other customers reduce the volumes of oil, natural gas and natural gas liquids 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.

We are subject to compliance with environmental, safety and health laws and regulations that may expose us to significant costs and liabilities.

The operations of our wells are subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment, environmental protection, and the occupational health and safety of employees. These laws and regulations may impose numerous obligations on our operations including the acquisition of permits, including drilling permits, to conduct regulated activities, the incurrence of capital expenditures to mitigate or prevent releases of materials from our facilities, the imposition of substantial liabilities for pollution resulting from our operations, and the application of specific health and safety criteria addressing worker protection. Examples of these environmental, health and safety laws include the following:

- the federal Clean Air Act and comparable state laws that impose various pre-construction, monitoring and reporting obligations related to air emissions from our facilities;

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

- the federal Resource, Conservation and Recovery Act (“RCRA”) and comparable state laws that impose requirements for the generation, treatment, storage and disposal of solid and hazardous waste from our facilities; and

- the federal Comprehensive Environmental Response, Compensation and Liability Act (“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 oil and natural gas 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.

A principal component of our business strategy is to grow our asset base and production through the acquisition of oil and natural gas 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 oil or natural gas 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 oil or natural gas 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, 2010, we have identified 460 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, D&M has 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 oil or natural gas 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 oil, natural gas and natural gas liquids 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 oil or natural gas 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 oil, natural gas and natural gas liquids 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.

Seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other operations in some of our operating areas and as a result, we generally perform the majority of our drilling in these areas 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. Additionally, 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. Generally, but not always, oil is typically in higher demand in the summer for its use in road construction and natural gas is in higher demand in the winter for heating. 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.

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 oil and natural gas price volatility on our cash flow from operations. Currently, we use a combination of fixed-price swaps, swaptions, put options and NYMEX collars to mitigate the volatility of future oil and natural gas 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.

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. 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 Senior Vice President of Operations. 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 oil and natural gas 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 oil, natural gas and natural gas liquids, 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 oil and natural gas 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 oil, natural gas and natural gas liquids 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 oil and natural gas 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 oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs of compliance with these laws and regulations and, consequently, adversely affect our profitability. At this time, we cannot predict the effect of this increase on our results of operations. Furthermore, we may be put at a competitive disadvantage to larger companies in our industry that can spread these additional costs over a greater number of wells and larger operating staff. Please read “Item1•Business•Operations•Environmental Matters and Regulation” and “Business•Operations•Other Regulation of the Oil and Natural Gas 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 oil, natural gas and natural gas liquids 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 oil, natural gas and natural gas liquids 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 oil, natural gas and natural gas liquids 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

Although we control ENP through our ownership of its general partner, ENP’s general partner owes fiduciary duties to ENP and ENP’s unitholders, which may conflict with our interests.

Conflicts of interest exist and may arise in the future as a result of the relationships between us and our affiliates, on the one hand, and ENP and its limited partners, on the other hand. The directors and officers of ENP’s general partner have fiduciary duties to manage ENP in a manner beneficial to us. At the same time, ENP’s general partner has fiduciary duties to manage ENP in a manner beneficial to ENP and its limited partners. The board of directors of ENP’s general partner will resolve any such conflict and has broad latitude to consider the interests of all parties to the conflict. The resolution of these conflicts may not always be in our best interest.

For example, conflicts of interest with ENP may arise in the following situations:

- the allocation of shared overhead expenses to ENP and us;
- the interpretation and enforcement of contractual obligations between us and our affiliates, on the one hand, and ENP, on the other hand;
- the determination of the amount of cash to be distributed to ENP’s partners and the amount of cash to be reserved for the future conduct of ENP’s business;
- the determination whether to make borrowings under ENP’s revolving credit facility to pay distributions to ENP’s partners, as applicable; and
- any decision we make in the future to engage in business activities independent of ENP.

The fiduciary duties of our officers and directors may conflict with those of ENP’s general partner.

Conflicts of interest may arise because of the relationships among ENP, its general partner and us. Our officers and directors have fiduciary duties to manage our business in a manner beneficial to us and our unitholders. Some of our officers and directors are also directors and officers of ENP’s general partner, and have fiduciary duties to manage the business of ENP in a manner beneficial to ENP and its unitholders. The resolution of these conflicts may not always be in our best interest or that of our unitholders.

Mr. Nami, who together with certain of his affiliates and related persons, own approximately 8.5% 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 2010, our unit price increased from a closing low of $18.93 on May 20, 2010 to a closing high of $29.65 on December 31, 2010. 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 oil and natural gas 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 oil and natural gas 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 oil and natural gas 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 or ENP as a corporation for federal income tax purposes or we or ENP 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 us and ENP 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) and ENP is a limited partnership (LP) under Delaware law, it is possible in certain circumstances for an LLC or an LP to be treated as a corporation for federal income tax purposes. Although we do not believe based upon our current operations or the current operations of ENP that we or ENP are so treated, a change in our business (or a change in current law) could cause us or ENP to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we or ENP 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 or on ENP as a corporation, our cash available for distribution to our unitholders could be reduced. Therefore, treatment of us or ENP 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 or ENP 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, Texas, Mississippi, Montana, North Dakota, Oklahoma, Arkansas and Wyoming. Each of these states, other than Texas and Wyoming, 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 have offices in Houston, Ft. Worth and Odessa, Texas; and Powell, Wyoming. As of December 31, 2010, the lease for the Houston office covered approximately 9,559 square feet of office space and runs through February 28, 2013. Subsequent to December 31, 2010, in connection with the Encore Acquisition completed on December 31, 2010, we entered into leases for the Ft. Worth and Odessa offices covering approximately 23,199 square feet and 2,440 square feet of office space, which run through November 30, 2013 and June 30, 2011, respectively. The total annual costs of our Houston lease for 2010 was approximately $0.2 million.

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. Discovery is ongoing between the parties.

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; however, on August 5, 2010, the case was bifurcated and the claims against the Company shall only be heard in the event liability is proven against the initial defendants. 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 0.5% of our estimated proved developed reserves as of December 31, 2010. 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. (REMOVED AND RESERVED)

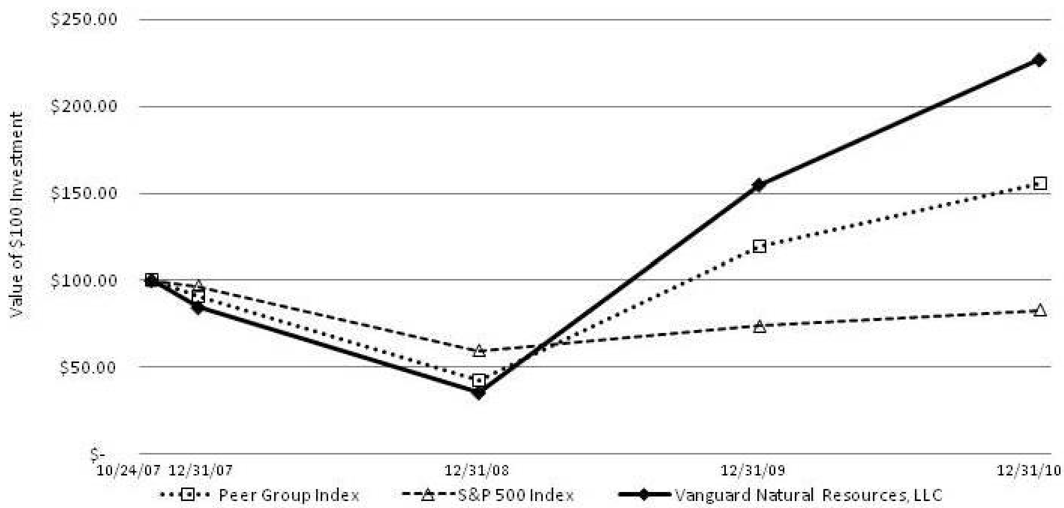
PART II

ITEM 5. MARKET FOR REGISTRANTS'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, 2011, there were 29,770,627 common units outstanding and approximately fifteen 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, 2011, the market price for our common units was $30.96 per unit, resulting in an aggregate market value of units held by non-affiliates of approximately $742,692,753. The following table presents the high and low sales price for our common units during the periods indicated.

	Common Units	
	High	**Low**
2010		
Fourth Quarter	$ 29.76	$ 24.98
Third Quarter	$ 26.46	$ 19.05
Second Quarter	$ 25.27	$ 16.94
First Quarter	$ 25.55	$ 19.27
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

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 oil and natural gas production publicly traded partnerships for 2007 and 2008. For 2010 and 2009, the Peer Group Index was a weighted composite of six and five natural gas and oil production publicly traded partnerships, respectively, which were paying a distribution for all of 2010 and 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. The following performance graph and related information shall not be deemed "soliciting material" or "filed" with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933 or the Exchange Act, each as amended, except to the extent that we specifically incorporate it by reference into such filing.



	October 24, 2007	December 31, 2007	December 31, 2008	December 31, 2009	December 31, 2010
Vanguard Natural Resources, LLC	$ 100	$ 84.48 (1)	$ 35.37 (1)	$ 154.88 (1)	$ 226.94 (1)
Peer Group Index	$ 100	$ 90.76	$ 42.75	$ 119.50	$ 155.81
S&P 500 Index	$ 100	$ 96.87	$ 59.59	$ 73.56	$ 82.96

(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), 2009 ($22.07) and 2010 ($29.65).

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
2010			
Fourth Quarter	$ 0.560	February 7, 2011	February 14, 2011
Third Quarter	$ 0.550	November 5, 2010	November 12, 2010
Second Quarter	$ 0.550	August 6, 2010	August 13, 2010
First Quarter	$ 0.525	May 7, 2010	May 14, 2010
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

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. 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.

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, 2010.

Recent Sales of Unregistered Securities and Use of Proceeds. On December 31, 2010, we completed the acquisition of all of the member interests in Encore Energy Partners GP LLC and 20,924,055 common units representing limited partnership interests in Encore Energy Partners LP from Denbury Resources Inc. As consideration for the purchase, we paid $300.0 million in cash and issued 3,137,255 unregistered common units, at an agreed upon price of $25.50 per unit, valued at the closing price of $29.65 at December 31, 2010. We did not repurchase any of our common units during the fourth quarter of 2010.

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 year ended December 31, 2006 and the balance sheet data as of December 31, 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 oil and natural gas 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. Starting January 1, 2008, unrealized gains and losses were recorded in earnings as all commodity and interest rate derivative contracts were either de-designated as cash flow hedges or they failed to meet the hedge documentation requirements for cash flow hedges.

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." This table does not include the operating results of the subsidiaries we acquired in the Encore Acquisition at December 31, 2010, however, the cash used in investing activities includes the Encore Acquistion, net of cash acquired.

	Year Ended December 31, (6)				
	Vanguard				Vanguard Predecessor
(in thousands, except per unit data)	**2010**	**2009**	**2008**	**2007**	**2006**
Statement of Operations Data:					
Revenues:					
Oil, natural gas and natural gas liquids sales	$ 85,357	$ 46,035	$ 68,850	$ 34,541	$ 38,184
Gain (loss) on commodity cash flow hedges (1)	(2,832)	(2,380)	269	(702)	•
Realized gain (loss) on other commodity derivative contracts (1)	24,774	29,993	(6,552)	•	(2,208)
Unrealized gain (loss) on other commodity derivative contracts (1)	(14,145)	(19,043)	39,029	•	17,748
Other	•	•	•	•	665
Total revenues	93,154	54,605	101,596	33,839	54,389
Costs and Expenses:					
Lease operating expenses	18,471	12,652	11,112	5,066	4,896
Depreciation, depletion, amortization and accretion	22,231	14,610	14,910	8,981	8,633
Impairment of oil and natural gas properties	•	110,154	58,887	•	•
Selling, general and administrative expenses	10,134(2)	10,644(2)	6,715(2)	3,507(2)	5,199
Bad debt expense	•	•	•	1,007	•
Production and other taxes	6,840	3,845	4,965	2,054	1,774
Total costs and expenses	57,676	151,905	96,589	20,615	20,502
Income (Loss) from Operations:	35,478	(97,300)	5,007	13,224	33,887
Other Income (Expense):					
Interest income	1	•	17	62	40
Interest and financing expenses	(5,766)	(4,276)	(5,491)	(8,135)	(7,372)
Realized loss on interest rate derivative contracts	(1,799)	(1,903)	(107)	•	•
Gain (loss) on acquisition of oil and natural gas properties	(5,680)	6,981	•	•	•
Unrealized gain (loss) on interest rate derivative contracts	(349)	763	(3,178)	•	•
Loss on extinguishment of debt	•	•	•	(2,502)	•
Total other income (expenses)	(13,593)	1,565	(8,759)	(10,575)	(7,332)
Net Income (Loss)	$ 21,885	$ (95,735)	$ (3,752)	$ 2,649	$ 26,555
Net Income (Loss) Per Unit:					
Common and Class B units - basic & diluted	$ 1.00	$ (6.74)	$ (0.32)	$ 0.39	N/A(3)
Distributions Declared Per Unit	$ 2.15	$ 2.00	$ 1.77(4)	$ 0.425(4)	N/A(3)
Weighted Average Common Units Outstanding	21,500	13,791	11,374	6,533	N/A(3)

Cash Flow Data:					
Net cash provided by operating activities	$ 71,577	$ 52,155	$ 39,554	$ 1,373	$ 16,087
Net cash used in investing activities	$ (429,994)	$ (109,315)	$ (119,539)	$ (26,409)	$ (37,383)
Net cash provided by financing activities	$ 359,758	$ 57,644	$ 76,878	$ 26,415	$ 19,985
Other Financial Information:					
Adjusted EBITDA (5)	$ 80,396	$ 56,202	$ 48,754	$ 30,395	$ 24,772

(1) Oil and natural gas derivative contracts were used to reduce our exposure to changes in oil and natural gas 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 through 2010, the change in fair value through December 31, 2007 has been reclassified to earnings from accumulated other comprehensive loss and is classified as gain (loss) 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 (loss) on other commodity derivative contracts.

(2) Includes $1.0 million, $2.9 million, $3.6 million and $2.1 million of non-cash unit-based compensation expense in 2010, 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) In 2008, 2009 and 2010, we acquired certain oil and natural gas properties and related assets in the Permian Basin, south Texas and Mississippi. The operating results of these properties are included with ours from the date of acquisition forward.

(in thousands)	Vanguard 2010 (1)(4)	Vanguard 2009 (3)	Vanguard 2008 (2)	Vanguard 2007	Vanguard Predecessor 2006
Balance Sheet Data:					
Cash and cash equivalents	$ 1,828	$ 487	$ 3	$ 3,110	$ 1,731
Short-term derivative assets	24,115	16,190	22,184	4,017	•
Other current assets	35,752	11,566	9,691	4,826	20,438
Oil and natural gas properties, net of accumulated depreciation, depletion, amortization and accretion	1,063,403	172,525	182,269	106,983	104,684
Property, plant and equipment, net of accumulated depreciation	972	174	184	166	11,873
Long-term derivative assets	6,129	5,225	15,749	1,330	•
Other assets	6,580	4,533	2,482	10,747	•
Goodwill (5)	420,955	•	•	•	•
Other intangible assets	9,017	•	•	•	•
Total Assets	$1,568,751	$ 210,700	$ 232,562	$131,179	$ 138,726
Short-term derivative liabilities	$ 13,801	$ 253	$ 486	$ •	$ 2,022
Other current liabilities	35,578	12,166	7,278	5,355	11,505
Term loan- current	175,000	•	•	•	•
Long-term debt	410,500	129,800	135,000	37,400	94,068
Long-term derivative liabilities	35,034	2,036	2,313	5,903	•
Other long-term liabilities	29,445	6,159	2,134	190	418
Members' equity	320,731	60,286	85,351	82,331	30,713
Non-controlling interest in subsidiary	548,662	•	•	•	•
Total Liabilities and Members' Equity	$ 1,568,751	$ 210,700	$ 232,562	$ 131,179	$ 138,726

As of December 31,

(1) Includes the fair value of the Encore assets and liabilities we acquired on December 31, 2010.

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

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

(4) The Parker Creek acquisition closed on May 20, 2010.

(5) Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the Encore Acquisition completed on December 31, 2010.

Summary Reserve and Operating Data

The following tables show estimated net proved reserves based on a reserve report prepared by our independent petroleum engineers, D&M, and certain summary unaudited information with respect to our production and sales of oil, natural gas and natural gas liquids. 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•Oil, Natural Gas and Natural Gas Liquids Data•Proved Reserves" and "•Production and Price History" included in this Annual Report in evaluating the material presented below.

	As of December 31, 2010		
	VNR	ENP (1)	Total
Reserve Data:			
Estimated net proved reserves:			
Crude oil (MBbls)	10,678	27,443	38,121
Natural gas (Bcf)	79.4	74.5	153.9
Natural gas liquids (MBbls)	4,298	1,210	5,508
Total (MMBOE)	28.2	41.1	69.3
Proved developed (MMBOE)	18.7	37.0	55.7
Proved undeveloped (MMBOE)	9.5	4.1	13.6
Proved developed reserves as % of total proved reserves	66%	90%	80%
Standardized Measure (in millions) (2)	$ 414.9	$ 703.5	$ 1,118.4
Representative Oil and Natural Gas Prices (3):			
Oil•WTI per Bbl	$ 79.40	$ 79.43	
Natural gas•Henry Hub per MMBtu	$ 4.38	$ 4.45	

(1) Includes the non-controlling interest of approximately 53.3% at December 31, 2010.

(2) 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 subsidiaries which are 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."

(3) Oil and natural gas prices are based on spot prices per Bbl and MMBtu, respectively, calculated using the 12-month average price for January through December 2010, 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 (3)			Production Cost (4)
	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, 2010 (1)							
Sun TSH Field	40	2,586	15,025	$ 75.74	$ 7.59	$ 1.14	$ 5.77
Other	1,830	11,086	9,086	$ 76.54	$ 10.45	$ 0.99	$ 11.77
Total	1,870	13,672	24,111	$ 76.53	$ 9.91	$ 1.09	$ 10.72
Year Ended December 31, 2009 (2)							
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 (5)							
Total other	715	11,450	3,271	$ 85.69	$ 10.49	$ 1.18	$ 11.24

(1) Average daily production for 2010 calculated based on 365 days including production for the Parker Creek acquisition from the closing dates of these acquisitions.

(2) 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.

(3) 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.

(4) 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).

(5) 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 oil and natural gas 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 oil and natural gas properties;
- Change in fair value of derivative contracts;
- Deferred taxes;
- Unit-based compensation expense;
- Realized gains and losses on cancelled derivatives;
- Material transaction costs incurred on acquisitions; 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 (in thousands). This table does not include the operating results of the subsidiaries we acquired in the Encore Acquisition at December 31, 2010.

	Year Ended December 31,				
	Vanguard				Vanguard Predecessor
(in thousands)	**2010**	**2009**	**2008**	**2007**	**2006**
Net Income (Loss)	$ 21,885	$ (95,735)	$ (3,752)	$ 2,649	$ 26,555
Plus:					
Interest expense, including realized losses on interest rate derivative contracts	7,565	6,179	5,597	8,135	7,372
Loss on extinguishment of debt	•	•	•	2,502	•
Depreciation, depletion, amortization and accretion	22,231	14,610	14,910	8,981	8,633
Impairment of oil and natural gas properties	•	110,154	58,887	•	•
Bad debt expense	•	•	•	1,007	•
Amortization of premiums paid on derivative contracts	1,950	3,502	4,493	4,274	•
Amortization of value on derivative contracts acquired	1,995	3,619	733	•	•
Unrealized (gains) losses on other commodity and interest rate derivative contracts (1)	14,494	18,280	(35,851)	•	(17,748)
(Gain) loss on acquisitions of oil and natural gas properties	5,680	(6,981)	•	•	•
Deferred taxes	(12)	(302)	177	•	•
Unit-based compensation expense	847	2,483	3,577	2,132	•
Realized loss on cancelled derivatives	•	•	•	777	•
Unrealized fair value of phantom units granted to officers	179	4,299	•	•	•
Cash settlement of phantom units granted to officers	•	(3,906)	•	•	•
Material transaction costs incurred on acquisitions	3,583	•	•	•	•
Less:					
Interest income	1	•	17	62	40
Adjusted EBITDA	$ 80,396	$ 56,202	$ 48,754	$ 30,395	$ 24,772

(1) Oil and natural gas derivative contracts were used to reduce our exposure to changes in oil and natural gas 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 (loss) on other commodity derivative contracts. The changes in fair value of interest rate derivative contracts is recorded in earnings and classified as gain (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 Report, 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 oil and natural gas 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 oil and natural gas properties. We own a 100% controlling interest, through certain of our subsidiaries, in properties and oil and natural gas reserves located in four operating areas:

- the Permian Basin in west Texas and New Mexico;
- south Texas;
- the southern portion of the Appalachian Basin, primarily in southeast Kentucky and northeast Tennessee; and
- Mississippi.

In addition, we own an approximate 46.7% aggregate controlling interest through our subsidiary, ENP, in properties and oil and natural gas reserves located in four operating areas:

- the Permian Basin in west Texas and New Mexico;
- the Big Horn Basin in Wyoming and Montana;
- the Williston Basin in North Dakota and Montana; and
- the Arkoma Basin in Arkansas and Oklahoma.

At December 31, 2010, we owned working interests in 4,895 gross (2,270 net) productive wells, including those wells acquired in the Encore Acquisition, which are subject to a 53.3% non-controlling interest. In addition to these productive wells, we own leasehold acreage allowing us to drill new wells. As of December 31, 2010, we had a 40% working interest in approximately 109,291 gross undeveloped acres surrounding or adjacent to our existing wells located in the Appalachian Basin. In South Texas and the Permian Basin, VNR owns working interests ranging from 30-100% in approximately 15,890 undeveloped acres surrounding our existing wells. Additionally, ENP owns working interests ranging from 8-77% in approximately 15,372 undeveloped acres surrounding their existing wells in the Permian Basin, Big Horn Basin, Williston Basin and Arkoma Basin. Approximately 20% or 13.6 MMBOE of our estimated proved reserves were attributable to our working interests in undeveloped acreage. The proved undeveloped reserves that we acquired in connection with the Encore Acquisition are subject to a 53.3% non-controlling interest in ENP.

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.

Recent Developments

Encore Acquisition

On December 31, 2010, we completed an acquisition pursuant to a Purchase Agreement with Denbury Resources Inc. (“Denbury”), Encore Partners GP Holdings LLC, Encore Partners LP Holdings LLC and Encore Operating, L.P. (collectively, the “Encore Selling Parties” and, together with Denbury, the “Selling Parties”) to acquire (the “Encore Acquisition” or “Encore”) all of the member interest in ENP GP, the general partner of ENP and 20,924,055 common units representing limited partnership interests in ENP (the “ENP Units”), representing a 46.7% aggregate equity interest in ENP. As consideration for the purchase, we paid $300.0 million in cash and paid $80.0 million in stock by issuing 3,137,255 VNR common units, at an agreed upon price of $25.50 per unit, valued at the closing price of $29.65 at December 31, 2010.

In connection with closing of the Encore Acquisition, VNG entered into a Second Amended and Restated Administrative Services Agreement, dated December 31, 2010, with ENP, ENP GP, Encore Operating, L.P. (“Encore Operating”), OLLC and Denbury (the “Services Agreement”). The Services Agreement was amended solely to add VNG as a party and provide for VNG to assume the rights and obligations of Encore Operating and Denbury under the previous administrative services agreement going forward.

Pursuant to the Services Agreement, VNG will provide certain general and administrative services to ENP, ENP GP and the OLLC (collectively, the “ENP Group”) in exchange for a quarterly fee of $2.06 per barrel of oil equivalent of the ENP Group’s total net oil and gas production for the most recently-completed quarter, which fee is paid by ENP (the “Administrative Fee”). The Administrative Fee is subject to certain index-related adjustments on an annual basis. ENP also is obligated to reimburse VNG for all third-party expenses it incurs on behalf of the ENP Group. These terms are identical to the terms under which Denbury and Encore Operating provided administrative services to the ENP Group prior to the second amendment and restatement of the Services Agreement.

As the acquisition was completed on December 31, 2010, no results of operations were included in the consolidated statement of operations for the year ended December 31, 2010. The fair value of the assets and liabilities we acquired on December 31, 2010 in the Encore acquisition and cash flows associated with the transaction were included in the consolidated balance sheet as of December 31, 2010 and the statement of cash flows for the year ended December 31, 2010, respectively.

Acquisitions of Oil and Natural Gas Properties

Permian Basin Acquisition

On December 21, 2007, we entered in to a Purchase and Sale Agreement with the Apache Corporation for the purchase of certain oil and natural gas properties located in ten separate fields in the Permian Basin of west Texas and southeastern New Mexico, 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. 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, 2010, based on a reserve report prepared by our independent reserve engineers, these acquired properties have estimated proved reserves of 3.4 MMBOE, 90% 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 oil and natural gas 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 VNR common units. 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 2011 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, 2010, based on a reserve report prepared by our independent reserve engineers, these acquired properties have estimated proved reserves of 2.8 MMBOE, 99% of which is natural gas and natural gas liquids and 60% of which is proved developed producing.

Sun TSH Acquisition

On July 17, 2009, we entered into a Purchase and Sale Agreement to acquire certain oil and natural gas 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. 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, 2010, based on a reserve report prepared by our independent reserve engineers, these acquired properties have estimated proved reserves of 6.1 MMBOE, 98% of which is natural gas and natural gas liquids and 60% of which 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 oil and natural gas properties located in Ward County, Texas in the Permian Basin from private sellers, referred to as the "Ward County acquisition." This transaction had an effective date of October 1, 2009 and was closed on December 2, 2009 for $55.0 million. This acquisition was initially funded with borrowings under our reserve-based credit facility with borrowings being reduced by $40.3 million shortly thereafter with the proceeds from a 2.3 million common unit offering. We operate all but one of the ten wells acquired in this transaction. As of December 31, 2010, based on a reserve report prepared by our independent reserve engineers, these acquired properties have estimated proved reserves of 3.7 MMBOE, 74% of which is oil and 59% of which is proved developed producing. In an effort to support stable cash flows from this transaction, we entered into crude oil swaps based on NYMEX pricing for approximately 90% of the estimated oil production from existing producing wells in the acquired properties for the period beginning January 2010 through December 2013.

Parker Creek Acquisition

On April 30, 2010, we entered into a definitive agreement with a private seller for the acquisition of certain oil and natural gas properties located in Mississippi, Texas and New Mexico. We refer to this acquisition as the "Parker Creek acquisition." The purchase price for said assets was $113.1 million with an effective date of May 1, 2010. We completed this acquisition on May 20, 2010. The adjusted purchase price of $114.3 million considered final purchase price adjustments of approximately $1.2 million. The purchase price was funded from the approximate $71.5 million in net proceeds from our May 2010 equity offering and with borrowings under the Company's existing reserve-based credit facility. In conjunction with the acquisition, we entered into crude oil hedges covering approximately 56% of the estimated production from proved producing reserves through 2013 at a weighted average price of $91.70 per barrel. As of December 31, 2010, based on a reserve report prepared by our independent reserve engineers, these acquired properties had estimated proved reserves of 4.3 MMBOE, 97% of which is oil and 37% of which is proved developed producing.

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. 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.

Shelf Registration Statements

In November 2008, ENP's shelf registration statement on Form S-3 was declared effective by the SEC. Under the shelf registration statement, ENP may offer common units, senior debt, or subordinated debt in one or more offerings with a total initial offering price of up to $1 billion. In May 2009, ENP issued 2,760,000 common units under its shelf registration statement at a price to the public of $15.60 per common unit. In July 2009, ENP issued 9,430,000 common units under its shelf registration statement at a price to the public of $14.30 per common unit. As a result of these offerings, as of December 31, 2010, ENP has approximately $822.1 million remaining available under its 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 2009 shelf registration statement is determined at the time of the offerings. The shelf registration statement does not provide assurance that we will or could sell any such securities. Our ability to utilize the shelf registration statement for the purpose of issuing, from time to time, any combination of debt securities or common units will depend upon, among other things, market conditions and the existence of investors who wish to purchase our securities at prices acceptable to us.

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

In May 2010, we completed an offering of 3.3 million of our common units. The units were offered to the public at a price of $23.00 per unit. We received proceeds of approximately $71.5 million from the offering, after deducting underwriting discounts of $3.2 million and offering costs of $0.1 million.

In July 2010, we filed a registration statement with the SEC which registered offerings of up to $800.0 million of any combination of debt securities, common units and guarantees of debt securities by our subsidiaries. Net proceeds, terms and pricing of the offering of securities issued under the 2010 shelf registration statement are 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 2010, we entered into an equity distribution agreement relating to our common units representing limited liability company interests having an aggregate offering price of up to $60.0 million. In accordance with the terms of the equity distribution agreement we may offer and sell up to the maximum dollar amount of our units from time to time through our sales agent. Sales of the units, if any, may be made by means of ordinary brokers' transactions through the facilities of the New York Stock Exchange, or NYSE, at market prices. Our sales agent will receive from us a commission of 1.25% based on the gross sales price per unit for any units sold through it as agent under the equity distribution agreement. During September through December 2010, we received net proceeds of approximately $6.3 million from the sales of 240,111 common units, after commissions.

In October 2010, we completed an offering of 4.8 million of our common units. The units were offered to the public at a price of $25.40 per unit. We received net proceeds of approximately $115.8 million from the offering, after deducting underwriting discounts of $5.1 million and offering costs of $0.3 million. We paid $3.7 million of the proceeds of this offering to redeem 150,000 common units from our founding unitholder. The remaining net proceeds of $112.1 million were used to pay down outstanding borrowings under our reserve-based credit facility.

As a result of these offerings, as of December 31, 2010, we have approximately $62.6 million and $678.8 million remaining available under our 2009 and 2010 shelf registration statements, respectively.

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 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.

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.

Oil, natural gas and natural gas liquids prices historically have been volatile and may fluctuate widely in the future. Sustained periods of low prices for oil, natural gas and natural gas liquids could materially and adversely affect our financial position, our results of operations, the quantities of oil, natural gas and natural gas liquids reserves that we can economically produce, our access to capital and our ability to pay distributions. We have mitigated the volatility on our cash flows with natural gas price derivative contracts through 2013 and oil price derivative contracts through 2014. These hedges are placed on a portion of our proved producing and a portion of our total anticipated production during this time frame. As oil, natural gas and natural gas liquids 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 oil, natural gas and natural gas liquids production declines. As a given well's initial reservoir pressures are depleted, oil, natural gas and natural gas liquids 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, 2010, we drilled and completed two gross (two net) wells on operated properties and drilled and completed six gross (2.6 net) non-operated wells. 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, in the event of significant declines 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 2011.

Results of Operations

The following table sets forth selected financial and operating data for the periods indicated. This table does not include the operating results of the subsidiaries we acquired in the Encore Acquisition at December 31, 2010.

	Year Ended December 31, (1)		
	2010	**2009**	**2008**
		(in thousands)	
Revenues:			
Oil sales	$ 50,022	$ 19,940	$ 23,930
Gas sales	25,778	21,966	43,502
Natural gas liquids sales	9,557	4,129	1,418
Oil, natural gas and natural gas liquids sales	85,357	46,035	68,850
Gain (loss) on commodity cash flow hedges	(2,832)	(2,380)	269
Realized gain (loss) on other commodity derivative contracts	24,774	29,993	(6,552)
Unrealized gain (loss) on other commodity derivative contracts	(14,145)	(19,043)	39,029
Total revenues	$ 93,154	$ 54,605	$ 101,596
Costs and expenses:			
Lease operating expenses	$ 18,471	$ 12,652	$ 11,112
Depreciation, depletion, amortization and accretion	22,231	14,610	14,910
Impairment of oil and natural gas properties	•	110,154	58,887
Selling, general and administrative expenses	10,134	10,644	6,715
Production and other taxes	6,840	3,845	4,965
Total costs and expenses	$ 57,676	$ 151,905	$ 96,589
Other income and expenses:			
Interest expense, net	$ (5,765)	$ (4,276)	$ (5,474)
Realized loss on interest rate derivative contracts	$ (1,799)	$ (1,903)	$ (107)
Gain (loss) on acquisition of oil and natural gas properties	$ (5,680)	$ 6,981	$ •
Unrealized gain (loss) on interest rate derivative contracts	$ (349)	$ 763	$ (3,178)

(1) In 2008, 2009 and 2010, we acquired certain oil and natural gas properties and related assets in the Permian Basin, south Texas and Mississippi. The operating results of these properties are included with ours from the date of acquisition forward.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

Revenues

Oil, natural gas and natural gas liquids sales increased $39.3 million to $85.3 million during the year ended December 31, 2010 as compared to the same period in 2009. The key revenue measurements were as follows:

	Year Ended December 31, 2010 (1)	Year Ended December 31, 2009	Percentage Increase (Decrease)
Net Natural Gas Production:			
Appalachian gas (MMcf)	2,924	3,103	(6)%
Permian gas (MMcf)	381	225(2)	69%
South Texas gas (MMcf)	1,685(3)	1,214(4)	39%
Total natural gas production (MMcf)	4,990	4,542	10%
Average Appalachian daily gas production (Mcf/day)	8,010	8,502	(6)%
Average Permian daily gas production (Mcf/day)	1,044	616(2)	69%
Average South Texas daily gas production (Mcf/day)	4,618(3)	3,326(4)	39%
Average Vanguard daily gas production (Mcf/day)	13,672	12,444	10%
Average Natural Gas Sales Price per Mcf:			
Net realized gas price, including hedges	$9.91(5)	$11.15(5)	(11)%
Net realized gas price, excluding hedges	$5.17	$4.84	7%
Net Oil Production:			
Appalachian oil (Bbls)	115,384	93,713	23%
Permian oil (Bbls)	398,728	242,301(2)	65%
South Texas oil (Bbls)	19,668(3)	9,386(4)	110%
Mississippi oil (Bbls)	148,667(3)	•(3)	N/A
Total oil production (Bbls)	682,447	345,400	98%
Average Appalachian daily oil production (Bbls/day)	316	257	23%
Average Permian daily oil production (Bbls/day)	1,093	664(2)	65%
Average South Texas daily oil production (Bbls/day)	54(3)	26(4)	110%
Average Mississippi daily oil production (Bbls/day)	407(3)	•(3)	N/A
Average Vanguard daily oil production (Bbls/day)	1,870	947	98%
Average Oil Sales Price per Bbl:			
Net realized oil price, including hedges	$76.53(5)	$75.26(5)	2%
Net realized oil price, excluding hedges	$73.30	$57.73	27%
Net Natural Gas Liquids Production:			
Permian natural gas liquids (Gal)	1,510,160	454,940(2)	232%
South Texas natural gas liquids (Gal)	7,290,129(3)	4,366,016(4)	67%
Total natural gas liquids production (Gal)	8,800,289	4,820,956	83%
Average Permian daily natural gas liquids production (Gal/day)	4,138	1,247(2)	232%
Average South Texas daily natural gas liquids production (Gal/day)	19,973(3)	11,961(4)	67%
Average Vanguard daily natural gas liquids production (Gal/day)	24,111	13,208	83%
Average Natural Gas Liquids Sales Price per Gal:			
Net realized natural gas liquids price	$1.09	$0.86	27%

(1) Excludes production results for the oil and natural gas properties acquired in the Encore Acquisition as the acquisition closed on December 31, 2010.
(2) 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 Permian area, calculated using the actual number of days for the Ward County acquisition from the closing date to the end of the reported period, was 899 Mcf/day of natural gas, 1,040 Bbls/day of oil and 4,294 Gal/day of natural gas liquids during 2009.
(3) South Texas area includes production from the Dos Hermanos, Sun TSH and a portion of the Parker Creek acquisitions. The Parker Creek acquisition closed on May 20, 2010 and, as such, only seven months and eleven days of operations are included in the year ended December 31, 2010, and no 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 South Texas area, calculated using the actual number of days for the Parker Creek acquisition from the closing date to the end of the reported period, was 4,663 Mcf/day of natural gas, 60 Bbls/day of oil and 20,006 Gal/day of natural gas liquids during 2010. The average daily production for the Mississippi area, calculated using the actual number of days for the Parker Creek acquisition from the closing date to the end of the reported period, was 26 Mcf/day of natural gas and 607 Bbls/day of oil during 2010.
(4) 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 South Texas area, calculated using the actual number of days for the Sun TSH acquisition from the closing date to the end of the reported period, was 5,197 Mcf/day of natural gas, 69 Bbls/day of oil and 23,770 Gal/day of natural gas liquids during 2009.
(5) Excludes amortization of premiums paid and amortization of value on derivative contracts acquired.

The increase in oil, natural gas and natural gas liquids sales during the year ended December 31, 2010 compared to the same period in 2009 was due primarily to the increases in commodity prices and an increase in production. We experienced a 7% increase in the average realized natural gas sales price received (excluding hedges) and a 27% increase in the average realized oil price (excluding hedges). Additionally, our total production increased by 42% on a BOE basis. The increase in production for the year ended December 31, 2010 over the comparable period in 2009 was primarily attributable to the impact from the Sun TSH, Ward County and Parker Creek acquisitions completed in August 2009, December 2009 and May 2010, respectively. In Appalachia, we experienced a 6% decrease in natural gas production which was partially offset by a 23% increase in oil production during year ended December 31, 2010 compared to the same period in 2009 for a net production decline of 1% on a BOE basis. While our natural gas wells had lower production during 2010, we experienced a 23% increase in Appalachian oil production primarily due to our focus on completing seven vertical oil wells in 2009.

Hedging and Price Risk Management Activities

During the years ended December 31, 2010 and 2009, the Company recognized $2.8 million and $2.4 million in losses on commodity cash flow hedges, respectively. These amounts relate to derivative contracts that the Company entered into in order to mitigate commodity price exposure on a portion of our expected production and designated as cash flow hedges. The losses on commodity cash flow hedges for the years ended December 31, 2010 and 2009 relate to the amounts that settled in those years and have been reclassified to earnings from accumulated other comprehensive loss. During the years ended December 31, 2010 and 2009, the Company recognized a $24.8 million and $30.0 million realized gain on other commodity derivative contracts, respectively, related to the settlements recognized during those periods and a $14.1 million and $19.0 million loss related to the change in fair value of derivative contracts not meeting the criteria for cash flow hedge accounting in those periods, respectively.

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 temporarily increased to $95 per well per month beginning March 1, 2009 through December 31, 2009 pursuant to an agreement whereunder Vinland provided 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 temporary fee based upon the actual costs incurred by Vinland to provide gathering and transportation services plus a $0.05 per Mcf margin. Both temporary amendments expired on December 31, 2009 and all the terms of the agreements reverted back to the original agreements.

In June 2010, we began discussions with Vinland regarding an amendment to the gathering and compression agreement to go into effect beginning on July 1, 2010. The amended agreement would provide gathering and compression services based upon actual costs plus a margin of $.055 per mcf. We and Vinland agreed in principle to this change effective July 1, 2010 and we have jointly operated on this basis although the formal agreements have yet to be signed. We are currently negotiating other agreements with Vinland concerning our joint operations and our intent is to have all our operations governed under a single set of agreements, including this amendment to the gathering and compression agreement. Lease operating expenses increased by $5.8 million to $18.5 million for the year ended December 31, 2010 as compared to the year ended December 31, 2009 of which $4.0 million related to the Sun TSH and Ward County and Parker Creek acquisitions and $1.8 million related to increase lease operating expenses for wells in Appalachia.

Depreciation, depletion, amortization and accretion increased to approximately $22.2 million for the year ended December 31, 2010 from approximately $14.6 million for the year ended December 31, 2009 due primarily to the additional depletion recorded on the oil and natural gas properties acquired in the Sun TSH, Ward County and Parker Creek acquisitions.

An impairment of oil and natural gas properties in the amount of $110.2 million was recognized during the year ended December 31, 2009 as the unamortized cost of oil and natural gas properties exceeded the sum of the estimated future net revenues from proved properties using the 12-month average price of oil and natural gas, 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 oil and natural gas prices based upon the 12-month average price, we recorded an additional 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 oil and natural gas 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. No impairment of oil and natural gas properties was necessary during the year ended December 31, 2010. In addition, our analysis of goodwill concluded that there was no impairment of goodwill as of December 31, 2010.

Selling, general and administrative expenses include the costs of our administrative employees and executive officers, related benefits, office leases, professional fees and other costs not directly associated with field operations. These expenses for the year ended December 31, 2010 decreased $0.5 million as compared to the year ended December 31, 2009 principally due to a decrease in non-cash compensation charges related to the grant of restricted Class B units to officers and an employee, the grant of phantom units to officers and the grant of common units to board members and employees. Non-cash compensation charges declined $5.8 million to $1.0 million for the year ended December 31, 2010. Offsetting this decline was a $3.6 million increase in general and administrative expenses primarily related to transaction costs incurred in connection with the Encore Acquisition and a $1.6 million increase in bonuses awarded to employees.

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 $3.0 million for the year ended December 31, 2010 as compared to the same period in 2009. Severance taxes increased $2.2 million as a result of increased oil, natural gas and natural gas liquids sales. Texas margin and other corporate taxes increased by $0.7 million and ad valorem taxes increased by $0.1 million primarily due to an increase of $0.6 million in the taxes on oil and natural gas properties acquired in the Sun TSH, Ward County and Parker Creek acquisitions, offset by a $0.5 million decrease in the taxes on Appalachia properties.

Other Income and Expense

Interest expense increased to $5.8 million for the year ended December 31, 2010 compared to $4.3 million for the year ended December 31, 2009 primarily due to higher interest rates and higher average outstanding debt for the year ended December 31, 2010.

In accordance with the guidance contained within ASC Topic 805, the measurement of the fair value at acquisition date of the assets acquired in the Parker Creek acquisition as compared to the fair value of consideration transferred, adjusted for purchase price adjustments, resulted in goodwill of $5.7 million, which was immediately impaired and recorded as a loss for the year ended December 31, 2010. The measurement of the fair value at acquisition date of the assets acquired in the Sun TSH and Ward County acquisitions as compared to the fair value of consideration transferred, adjusted for purchase price adjustments, resulted in a gain of $5.9 million and $ 1.1 million, respectively, for the year ended December 31, 2009. This gain and loss resulted from the increases and decreases in oil and natural gas prices used to value the reserves.

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

Revenues

Oil, natural gas and natural gas liquids 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,		Percentage
	2009	**2008**	**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)	184%
Average Vanguard daily gas production (Mcf/day)	12,444	11,450	8%
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	91%
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)	352%
Average Vanguard daily natural gas liquids production (Gal/day)	13,208	3,271	303%
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 Permian area, calculated using the actual number of days for the Ward County acquisition from the closing date to the end of the reported period, was 899 Mcf/day of natural gas, 1,040 Bbls/day of oil and 4,294 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 South Texas area, calculated using the actual number of days for the Sun TSH acquisition from the closing date to the end of the reported period,, was 5,197 Mcf/day of natural gas, 69 Bbls/day of oil and 23,770 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 oil, natural gas and natural gas liquids 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 BOE 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 BOE 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 compared to a gain of $0.3 million for the year ended December 31, 2008. 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 and gain on commodity cash flow hedges for the years ended December 31, 2009 and 2008 relate to the amounts that settled in those periods and have 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. Comparatively, 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. 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 months 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 oil and natural gas 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 oil and natural gas properties acquired in the Sun TSH and Ward County acquisitions.

An impairment of oil and natural gas properties in the amount of $110.2 million was recognized during the year ended December 31, 2009 as the unamortized cost of oil and natural gas properties exceeded the sum of the estimated future net revenues from proved properties using the 12-month average price of oil and natural gas, 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 oil and natural gas prices based upon the 12-month average price, we recorded an additional 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 oil and natural gas 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 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 was equal to 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 oil, natural gas and natural gas liquids 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.

Other Income and Expense

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.

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 Oil and Natural Gas Properties

The accounting for our business is subject to special accounting rules that are unique to the oil and natural gas 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 proved 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 oil and natural gas properties. Under this method, we capitalize all acquisition, exploration and development costs for the purpose of finding oil, natural gas and natural gas liquids reserves, including salaries, benefits and other internal costs directly related to these finding activities. For the years ended December 31, 2010 and 2009, 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 oil and natural gas 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 oil and natural gas 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 oil and natural gas properties is limited to the sum of the estimated future net revenues from proved properties using oil and natural gas 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 2010 and 2009, most of our hedges were not considered cash flow hedges for accounting purposes and thus a significant portion of the value of our hedges were not considered in our ceiling test calculations. The SEC's Final Rule, "Modernization of Oil and Gas Reporting," requires that the present value of future net revenue from proved properties be calculated based upon the 12-month average price.

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 "Oil, natural gas and natural gas liquids Reserve Quantities" below. Due to the imprecision in estimating oil, natural gas and natural gas liquids reserves as well as the potential volatility in oil, natural gas and natural gas liquids prices and their effect on the carrying value of our proved oil, natural gas and natural gas liquids 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 oil and natural gas properties. These factors include declining oil, natural gas and natural gas liquids prices, downward revisions in estimated proved oil, natural gas and natural gas liquids reserve quantities and unsuccessful drilling activities.

While no ceiling test impairment was required during 2010, we recorded a non-cash ceiling test impairment of oil and natural gas 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 oil and natural gas prices based upon the 12-month average price, we recorded an additional 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 oil and natural gas properties for the year ended December 31, 2008 of $58.9 million as a result of a decline in oil and natural gas prices at the measurement date. This impairment was calculated based on year end prices of $5.71 per MMBtu for natural gas and $41.00 per barrel of crude oil.

Business Combinations

We account for business combinations under ASC Topic 805, "Business Combinations." We recognize and measure in our financial statements the fair value of all identifiable assets acquired, the liabilities assumed, any non-controlling interests in the acquiree and the goodwill acquired in all transactions in which control of one or more businesses is obtained.

Goodwill and Other Intangible Assets

We apply the provisions of the "*Goodwill and Other Intangible Assets*" topic of the ASC. Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in business combinations. Goodwill is assessed for impairment annually on October 1 or whenever indicators of impairment exist. The goodwill test is performed at the reporting unit level. We have determined that we have two reporting units, which are Vanguard's historical oil and natural gas operations in the United States and ENP's oil and natural gas operations in the United States. At December 31, 2010, all goodwill was assigned to the reporting unit comprised of ENP's oil and natural gas operations in the United States. If indicators of impairment are determined to exist, an impairment charge is recognized for the amount by which the carrying value of goodwill exceeds its implied fair value.

We utilize both a market capitalization and an income approach to determine the fair value of our reporting units. The primary component of the income approach is the estimated discounted future net cash flows expected to be recovered from the reporting unit's oil and natural gas properties. Our analysis concluded that there was no impairment of goodwill as of December 31, 2010. Any sharp decreases in the prices of oil and natural gas or any significant negative reserve adjustments from the December 31, 2010 assessment could change our estimates of the fair value of our reporting units and could result in an impairment charge.

Intangible assets with definite useful lives are amortized over their estimated useful lives. We evaluate the recoverability of intangible assets with definite useful lives whenever events or changes in circumstances indicate that the carrying value of the asset may not be fully recoverable. An impairment loss exists when the estimated undiscounted cash flows expected to result from the use of the asset and its eventual disposition are less than its carrying amount.

We allocate the purchase price paid for the acquisition of a business to the assets and liabilities acquired based on the estimated fair values of those assets and liabilities. Estimates of fair value are based upon, among other things, reserve estimates, anticipated future prices and costs, and expected net cash flows to be generated. These estimates are often highly subjective and may have a material impact on the amounts recorded for acquired assets and liabilities.

Asset Retirement Obligation

We have obligations to remove tangible equipment and restore land at the end of an oil or natural gas well's life. Our removal and restoration obligations are primarily associated with plugging and abandoning wells and the decommissioning of ENP's Elk Basin gas plant. 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 oil and natural gas property balance.

Oil, Natural Gas and Natural Gas Liquids 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 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, 2010 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 oil, natural gas and natural gas liquids are recognized when oil, natural gas and natural gas liquids 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 oil, natural gas and natural gas liquids 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 oil, natural gas and natural gas liquids supplies. As a result, our revenues from the sale of oil, natural gas and natural gas liquids will suffer if market prices decline and benefit if they increase without consideration of hedging. We believe that the pricing provisions of our oil, natural gas and natural gas liquids contracts are customary in the industry. To the extent actual volumes and prices of oil and natural gas sales are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and prices for those properties are estimated and recorded.

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, 2010 or 2009.

Price Risk Management Activities

We periodically use derivative financial instruments to achieve a more predictable cash flow from our oil and natural gas production by reducing our exposure to price fluctuations. Currently, these derivative financial instruments include fixed-price swaps, swaptions, put options 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 USA, LLP, the Company's then 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 oil and natural gas 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 qualify for 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.

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 vested after three years. The remaining 40,000 restricted Class B units were not granted and are not expected to be granted in the future. In October 2007 and February 2008, four board members were 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 was 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 was 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 January and March 2010, four board members were each granted 3,764 common units, one officer was granted 6,500 common units and one board member was granted 2,663 common units each of which will vest after one year.

In February 2010, the Company and VNRH entered into second amended and restated Executive Employment Agreements (the "Amended Agreements") with two executives. The Amended Agreements were effective January 1, 2010 and will continue until January 1, 2013, with subsequent one year renewals in the event that neither we, VNRH nor the executives have given notice to the other parties that the agreements should not be extended. Also in June 2010, the Company and VNRH entered into a second amended and restated Executive Employment Agreement (the "Amended Agreement") with one executive. The Amended Agreement was effective May 15, 2010 and will continue until May 15, 2013, with subsequent one year renewals in the event that neither we, VNRH nor the executive have given notice to the other parties that the agreements should not be extended. All three Amended Agreements provide for an annual base salary and include an annual bonus structure for the executives. The annual bonus will be calculated based upon two company performance elements, absolute target distribution growth and relative unit performance to peer group, as well as a third discretionary element to be determined by our board of directors for the Amended Agreements entered into in February 2010 and by the Chief Executive officer for the Amended Agreement entered into in June 2010. Each of the three components will be weighted equally in calculating the respective executive officer's annual bonus. The annual bonus does not require a minimum payout, although the maximum payout may not exceed two times the respective executive's annual base salary. At December 31, 2010, an accrued liability and compensation expense of $1.5 million was recognized in the selling, general and administrative expenses line item in the consolidated statement of operations.

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

In addition, the Amended Agreements entered into in February 2010 provide for each executive to receive an annual grant of 15,000 phantom units granted pursuant to the LTIP and the Amended Agreement entered into in June 2010 provides for the executive to receive an annual grant of 12,500 phantom units granted pursuant to the LTIP. The phantom units are also subject to a three year vesting period, although the vesting is not pro-rata, but a one-time event which shall occur on the three year anniversary of the date of grant so long as the executive remains continuously employed with the Company during such time. The phantom units are accompanied by dividend equivalent rights, which entitle the executives to receive the value of any distributions made by the Company on its units generally with respect to the number of phantom units that the 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. For each executive under the February 2010 amended agreements, the amount to be paid in connection with these phantom units, can be paid in cash or in units at the election of the officers and will be equal to the appreciation in value of the units from the date of the grant until the determination date (December 31, 2013). For the executive under the June 2010 amended agreement, the amount to be paid in connection with these phantom units, will be settled through the delivery of a number of units equal to the number of phantom units granted. As of December 31, 2010, an accrued liability associated with the phantom units of $0.2 million has been recorded and non-cash unit-based compensation expense of $0.2 million has been recognized for year ended December 31, 2010, in the selling, general and administrative expense line item in the consolidated statement of operations.

In January and February 2011, VNR employees were granted a total of 102,906 units which are subject to a four year vesting period. Additionally, in January 2011, ENP issued 140,007 restricted ENP units under the ENP LTIP, which are also subject to a four year vesting period, to Vanguard field employees performing services on ENP's properties.

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 common units granted to directors, officers and employees, we expect to incur $1.1 million in non-cash compensation expense for the year 2011. For the years ended December 31, 2010, 2009 and 2008, we recorded $0.8 million, $2.5 million and $3.6 million of non-cash compensation expense related to these units, respectively.

Capital Resources and Liquidity

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 oil and natural gas 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 financing arrangements and publicly offered equity, depending on market conditions. As of March 7, 2011, we have $43.0 million and $141.0 million available to be borrowed under our reserve-based credit facility and under ENP's revolving credit facility, respectively.

The borrowing base under our reserve-based credit facility 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 oil, natural gas and natural gas liquids prices) from our proved oil, natural gas and natural gas liquids reserves. In November 2010, our borrowing base was reduced from $240.0 million to $225.0 million pursuant to our semi-annual redetermination. If commodity prices decline and banks lower their internal projections of oil, natural gas and natural gas liquids 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 2011 to reduce our borrowings under our financing arrangements. 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 $71.6 million during the year ended December 31, 2010, compared to $52.2 million during the year ended December 31, 2009. The increase in cash provided by operating activities during the year ended December 31, 2010 as compared to the same period in 2009 was substantially generated from increased production volumes related to Sun TSH, Ward County and Parker Creek acquisitions which had been hedged at favorable prices generating significant realized gains on commodity derivative contracts. Changes in working capital increased total cash flows by $0.9 million in 2010 compared to $1.2 million in 2009. Contributing to the increase in the level of cash provided by operating activities during 2010 was a $2.7 million increase in accrued expenses that resulted primarily from the timing effects of payments for general operating expenses and bonuses awarded to employees. Offsetting this increase in cash flows from operating activities during 2010 was a $1.8 million increase in accounts receivable related to the timing of receipts from production from the acquisitions. 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, 2010 or 2009.

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.

Our cash flow from operations is subject to many variables, the most significant of which is the volatility of oil, natural gas and natural gas liquids prices. Oil, natural gas and natural gas liquids 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 oil, natural gas and natural gas liquids. We enter into derivative contracts to reduce the impact of commodity price volatility on operations. Currently, we use a combination of fixed-price swaps, swaptions, put options and NYMEX collars to reduce our exposure to the volatility in oil and natural gas 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 approximately $430.0 million for the year ended December 31, 2010, compared to $109.3 million during the same period in 2009. The increase in cash used in investing activities was primarily attributable to $298.6 million net cash paid for the Encore Acquisition, $115.8 million for the acquisition of natural gas and oil properties in the Parker Creek acquisition and $15.3 million for the drilling and development of natural gas and oil properties. During the year ended December 31, 2009, the cash used in investing activities was lower as a result of our decision to not drill wells in 2009 due to low natural gas prices. We used cash of $103.9 million for the Sun TSH and Ward County acquisitions and $5.0 million for the drilling and development of natural gas and oil properties.

Cash used in investing activities was approximately $109.3 million for the year ended December 31, 2009, compared to $119.5 million during the same period in 2008. The decrease in cash used in investing activities was primarily attributable to $103.9 million for the acquisition of natural gas and oil properties in the Sun TSH and Ward County acquisitions, $5.0 million for the drilling and development of natural gas and oil properties as compared to $100.7 million used for the Permian Basin and Dos Hermanos acquisitions and $18.2 million for the drilling and development of natural gas and oil properties during the year ended December 31, 2008.

Excluding any potential acquisitions, we currently anticipate a capital budget for 2011 of between $27.0 million and $28.5 million, which includes anticipated expenditures for VNR and our 46.7% aggregate controlling interest in ENP. VNR’s stand alone capital budget is expected to be between $17.9 and $18.7 million and will largely include oil focused drilling in our Bone Springs play in the Permian Basin and the Hosston formation in Mississippi. The remaining $9.1 to $9.8 million represents our net interest in capital spending for Encore which will focus primarily on oil drilling in the Big Horn Basin and a variety of recompletion projects in the Permian Basin. We anticipate that our cash flow from operations and available borrowing capacity under our financing arrangements will exceed our planned capital expenditures and other cash requirements for the year ended December 31, 2011. 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 $359.8 million for year ended December 31, 2010, compared to $57.6 million for the year ended December 31, 2009. During the year ended December 31, 2010, total net proceeds from our financing arrangements were $221.7 million. During 2010, $46.7 million was used for distributions to unitholders and $3.7 million was paid for financing costs, compared to $27.1 million used for distribution to unitholders and $3.1 million paid for financing costs in the comparable period in 2009. Proceeds from the equity offerings of 8.3 million common units completed during 2010 provided financing cash flows totaling $193.5 million, net of offering costs of $0.5 million, during the year ended December 31, 2010. Furthermore during 2010, $3.7 million was used to redeem common units held by our founding unitholder. Comparatively, 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 founding unitholder.

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.

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%. In December 2009, our borrowing base was increased from $170.0 million to $195.0 million pursuant to an interim redetermination requested by the Company due to the Ward County acquisition. In June 2010, we entered into the Second Amendment to Second Amended and Restated Credit Agreement, which (1) increased the borrowing base to $240 million, (2) allows us to enter into commodity price hedges with respect to the acquired production upon signing a purchase and sale agreement, (3) added a new lender, Credit Agricole Corporate and Investment Bank, and (4) allows us to hedge up to 85% of the projected oil and gas production from total proved reserves. Previously, our hedging was limited to 95% of the projected oil and gas production from proved developed producing reserves. In November 2010, our borrowing base under the reserve-based credit facility was reduced from $240.0 million to $225.0 million pursuant to our semi-annual redetermination. Also in November 2010, in connection with the Encore Acquisition, we entered into the Third Amendment to the Second Amended and Restated Credit Agreement to provide for certain amendments and modifications to allow us to incur indebtedness under, and grant the related security interests for, the Term Loan discussed below. Such amendments and modifications include the granting of a second priority lien on VNG’s interests in ENP GP and the ENP Units. In addition to the existing first priority liens on the assets of VNG and its subsidiaries, amounts outstanding under the reserve-based credit facility will also be secured by a second priority lien on VNG’s interest in ENP GP and the ENP Units. In December 2010, we entered into the Fourth Amendment to Second Amended and Restated Credit Agreement, which contains certain amendments necessary to exclude ENP GP’s pledge of the general partners interests issued by ENP that it owns as collateral securing the loans and other extensions of credit made to VNG pursuant to the Second Amended and Restated Credit Agreement. Additionally, the Fourth Amendment clarifies the amounts guaranteed by subsidiaries of VNG pursuant to guaranty agreements previously delivered by such subsidiaries. At December 31, 2010, we had $176.5 million outstanding under our reserve-based credit facility 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%

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 oil, natural gas and natural gas liquids prices) from our proved oil, natural gas and natural gas liquids reserves. In November 2010, our borrowing base was set at $225.0 million. Our next borrowing base redetermination is scheduled for April 2011 utilizing our December 31, 2010 reserve report. If commodity prices decline and banks lower their internal projections of oil, natural gas and natural gas liquids 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 2011 to reduce our borrowings under our reserve-based credit facility. As of March 7, 2011, we have $43.0 million available to be borrowed under our reserve-based credit facility.

Borrowings under the reserve-based credit facility are available for development and acquisition of oil and natural gas 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, 2010, we have elected for interest to be determined by reference to the LIBOR method described above. Interest is generally payable quarterly for domestic bank rate loans and at the applicable maturity date for LIBOR loans, but not less frequently than quarterly.

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

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

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

- consolidated net income plus interest expense, income taxes, depreciation, depletion, amortization, accretion, changes in fair value of derivative instruments and other similar charges, minus all non-cash income added to consolidated net income (which is equal to our Adjusted EBITDA), and giving pro forma effect to any acquisitions or capital expenditures, to interest expense of not less than 2.5 to 1.0;
- consolidated current assets, including the unused amount of the total commitments, to consolidated current liabilities of not less than 1.0 to 1.0, excluding non-cash assets and liabilities under ASC Topic 815, which includes the current portion of derivative contracts;
- 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 at December 31, 2010. 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.

Term Loan

Concurrent with the Encore Acquisition, VNG entered into a $175.0 million Term Loan with BNP Paribas to fund a portion of the consideration for the acquisition.

Borrowings under the Term Loan are comprised entirely of ABR Loans or Eurodollar Loans as VNG may request. Interest on ABR Borrowings under the Term Loan is payable quarterly on the last day of each March, June, September and December and accrues at a rate per annum equal to 6.50% plus the greater of (a) the prime rate in effect on such day, (b) the Federal Funds Effective Rate in effect on such day plus ½ of 1%, and (c) the Adjusted LIBO Rate in effect on such day plus 2%. Interest on Eurodollar Borrowings is payable on the last day of the interest period applicable to such borrowing, and in the case of a Eurodollar Borrowing with an interest period of more than three months' duration, each day prior to the last day of such interest period that occurs at intervals of three months' duration after the first day of such interest period and accrues at a rate per annum of 5.50% plus the Adjusted LIBO Rate for the interest period in effect for such borrowing. Amounts outstanding under the Term Loan may be prepaid prior to maturity, together with all accrued and unpaid interest relating to the amount prepaid, without prepayment penalty. The Term Loan contains various covenants, including restrictions on liens, restrictions on incurring other indebtedness without the lenders’ consent and restrictions on entering into certain transactions. The Term Loan matures the earlier of the first anniversary of the effective date (December 31, 2011) or the date following both the completion of any acquisition by Vanguard of the remainder of ENP and VNG’s execution and delivery of a new or amended and restated revolving credit facility replacing VNG’s current reserve-based credit facility.

Amounts outstanding under the Term Loan are secured by a second priority lien on all assets of VNG and its subsidiaries securing VNG's current reserve-based credit facility (other than VNG’s interest in ENP GP and the ENP Units) and a first priority lien on VNG’s interest in ENP GP and the ENP Units.

On December 31, 2010, VNG entered into the First Amendment to Term Loan Agreement, which contains certain amendments necessary to exclude ENP GP's pledge of the general partner's interests issued by ENP that it owns as collateral securing the loans and other extensions of credit made to VNG pursuant to the Term Loan Agreement.

The Term Loan 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 cash distributions by ENP and ENP GP with respect to ENP Interests (annualized) less the aggregate amount of cash used to purchase equity interests of VNR, 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 4.0 to 1.0.

We believe that we are in compliance with the terms of our Term Loan at December 31, 2010.

ENP's Revolving Credit Facility

The syndicate of lenders underwriting ENP's revolving credit facility includes 15 banking and other financial institutions. None of the lenders are underwriting more than 8% of the total commitments. We believe the number of lenders and the small percentage participation of each, provides adequate diversity and flexibility should further consolidation occur within the financial services industry.

ENP is a party to a five-year credit agreement dated March 7, 2007 (as amended, the "ENP Credit Agreement"). The ENP Credit Agreement matures on March 7, 2012. Any outstanding borrowings under the ENP Credit Agreement will become a current liability in March 2011. We are currently evaluating our options including extending the term of the ENP Credit Agreement or refinancing under a new revolving credit facility. Based on discussions with banks, all options are currently viable.

The ENP Credit Agreement provides for revolving credit loans to be made to ENP from time to time and letters of credit to be issued from time to time for the account of ENP or any of its restricted subsidiaries. The aggregate amount of the commitments of the lenders under the ENP Credit Agreement is $475 million. Availability under the ENP Credit Agreement is subject to a borrowing base of $375 million, which is redetermined semi-annually and upon requested special redeterminations. On December 31, 2010 and March 7, 2011, there were $234 million of outstanding borrowings and $141 million of borrowing capacity under the ENP Credit Agreement.

ENP incurs a quarterly commitment fee at a rate of 0.5% per year on the unused portion of the ENP Credit Agreement. Obligations under the ENP Credit Agreement are secured by a first-priority security interest in substantially all of ENP's proved oil and natural gas reserves and in the equity interests of ENP and its restricted subsidiaries. In addition, obligations under the ENP Credit Agreement are guaranteed by us and ENP's restricted subsidiaries. Obligations under the ENP Credit Agreement are non-recourse to Vanguard and its restricted subsidiaries.

Loans under the ENP Credit Agreement are subject to varying rates of interest based on (1) outstanding borrowings in relation to the borrowing base and (2) whether the loan is a Eurodollar loan or a base rate loan. Eurodollar loans bear interest at the Eurodollar rate plus the applicable margin indicated in the following table, and base rate loans bear interest at the base rate plus the applicable margin indicated in the following table:

Ratio of Outstanding Borrowings to Borrowing Base	*<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%

The “Eurodollar rate” for any interest period (either one, two, three, or six months, as selected by us) is the rate equal to the British Bankers Association LIBOR for deposits in dollars for a similar interest period. The “Base Rate” is calculated as the highest of: (1) the annual rate of interest announced by Bank of America, N.A. as its “prime rate” (2) the Federal Funds Effective Rate plus 0.5 %; or (3) except during a “LIBOR Unavailability Period,” the Eurodollar rate (for dollar deposits for a one-month term) for such day plus 1.0 %.

Any outstanding letters of credit reduce the availability under the ENP Credit Agreement. Borrowings under the ENP Credit Agreement may be repaid from time to time without penalty.

The ENP Credit Agreement contains covenants including, among others, the following:

- a prohibition against incurring debt, subject to permitted exceptions;
- a prohibition against purchasing or redeeming capital stock, or prepaying indebtedness, subject to permitted exceptions;
- a restriction on creating liens on our assets and the assets of ENP and its subsidiaries, subject to permitted exceptions;
- restrictions on merging and selling assets outside the ordinary course of business;
- restrictions on use of proceeds, investments, transactions with affiliates, or change of principal business;
- a provision limiting oil and natural gas hedging transactions (other than puts) to a volume not exceeding 75 % of anticipated production from proved producing reserves;
- a requirement that ENP maintain a ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0 (the “Current Ratio”);
- a requirement that ENP maintain a ratio of consolidated EBITDA, as defined in the ENP Credit Agreement, to the sum of consolidated net interest expense plus letter of credit fees of not less than 2.5 to 1.0 (the “Interest Coverage Ratio”); and
- a requirement that ENP maintain a ratio of consolidated funded debt to consolidated adjusted EBITDA, as defined in the ENP Credit Agreement, of not more than 3.5 to 1.0 (the “Leverage Ratio”).

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, 2010, there were no material loss contingencies.

Commitments and Contractual Obligations

A summary of our contractual obligations as of December 31, 2010 is provided in the following table.

	Payments Due by Year (in thousands)						
	2011	2012	2013	2014	2015	After 2015	Total
Management base salaries	$ 830	$ 830	$ 97	$ •	$ •	$ •	$ 1,757
Asset retirement obligations (1)	768	707	1,159	555	420	26,593	30,202
Derivative liabilities (2)	3,978	14,325	8,615	5,924	3,949	•	36,791
Financing arrangements (3)	175,000	410,500	•	•	•	•	585,500
Operating leases	960	932	251	•	•	•	2,143
Development commitments (4)	890	•	•	•	•	•	890
Total	$ 182,426	$ 427,294	$ 10,122	$ 6,479	$ 4,369	$ 26,593	$ 657,283

(1) Represents the discounted future plugging and abandonment costs of oil and natural gas wells and decommissioning of ENP's Elk Basin gas plant. Please read Note 7 of the Notes to the Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information regarding our asset retirement obligations.

(2) Represents liabilities for commodity and interest rate derivative contracts, the ultimate settlement of which are unknown because they are subject to continuing market risk. Please read "Item 7A•Quantitative and Qualitative Disclosures about Market Risk" and Note 6 of the Notes to the Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information regarding our commodity and interest rate derivative contracts.

(3) This table does not include interest to be paid on the principal balances shown as the interest rates on our financing arrangements are variable. Please read Note 4 of the Notes to the Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information regarding our long-term debt.

(4) Represents authorized purchases for work in process.

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 oil, natural gas and natural gas liquids prices and interest rates. The disclosures are not meant to be precise indicators of exposure, but rather indicators of potential exposure. 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 oil, natural gas and natural gas liquids production. Realized pricing is primarily driven by the Columbia Gas Appalachian Index ("TECO Index"), Henry Hub, Houston Ship Channel, West Texas ("Waha Index"), El Paso Natural Gas Company (Permian Basin) and Colorado Interstate Gas Company (Rocky Mountains) prices for natural gas production and the West Texas Intermediate Light Sweet price for oil production. Pricing for oil, natural gas and natural gas liquids 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 oil and natural gas 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, oil, natural gas and natural gas liquids prices were very volatile throughout 2009. We recorded a non-cash ceiling test impairment of oil and natural gas 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 oil and natural gas prices based upon the 12-month average price, we recorded an additional 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, 2010 would decrease from $1,118.4 million to $953.7 million, based on price sensitivity generated from an internal evaluation. This sensitivity analysis is calculated using natural gas prices ranging from $3.38 to $3.45 per MMBTU ($4.38 and $4.45 year-end prices less $1.00 (or 23% and 22%)) and oil prices ranging from $73.40 to $73.43 per barrel of crude oil ($79.40 and $79.43 year-end prices less $6.00 (or 8%)).

We enter into derivative contracts with respect to a portion of our projected oil and natural gas 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 oil and natural gas 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 oil and natural gas 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, 2010, the fair value of commodity derivative contracts was a liability of approximately $18.6 million, of which $10.3 million assets settle during the next twelve months. A 10% increase in the gas and oil index price above the December 31, 2010 price would result in a decrease in the fair value of all of our commodity derivative contracts entered into by VNG of approximately $18.3 million; conversely, a 10% decrease in the gas and oil index price would result in an increase of approximately $16.9 million. Based on ENP's open commodity derivative positions at December 31, 2010, a 10% increase in the respective NYMEX prices for oil and natural gas would increase ENP's net commodity derivative liability by approximately $47.6 million, while a 10% decrease in the respective NYMEX prices for oil and natural gas would decrease ENP's net commodity derivative liability by approximately $47.2 million. This sensitivity analysis measures the current value of the 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 oil and natural gas price indexes.

The following table summarizes commodity derivative contracts in place at December 31, 2010:

	Year 2011	Year 2012	Year 2013	Year 2014
Gas Positions:				
Fixed Price Swaps:				
VNG				
Notional Volume (MMBtu)	3,328,312	•	•	•
Fixed Price ($/MMBtu)	$ 7.83	$ •	$ •	$ •
ENP				
Notional Volume (MMBtu)	3,723,730	3,367,932	2,993,000	•
Fixed Price ($/MMBtu)	$ 6.06	$ 5.75	$ 5.10	$ •
Consolidated				
Notional Volume (MMBtu)	7,052,042	3,367,932	2,993,000	•
Fixed Price ($/MMBtu)	$ 6.89	$ 5.75	$ 5.10	$ •
Collars:				
VNG				
Notional Volume (MMBtu)	1,933,500	•	•	•
Floor Price ($/MMBtu)	$ 7.34	$ •	$ •	$ •
Ceiling Price ($/MMBtu)	$ 8.44	$ •	$ •	$ •
Puts:				
ENP				
Notional Volume (MMBtu)	1,240,270	328,668	•	•
Fixed Price ($/MMBtu)	$ 6.31	$ 6.76	$ •	$ •
Total Gas Positions:				
VNG				
Notional Volume (MMBtu)	5,261,812	•	•	•
ENP				
Notional Volume (MMBtu)	4,964,000	3,696,600	2,993,000	•
Consolidated				
Notional Volume (MMBtu)	10,225,812	3,696,600	2,993,000	•

	Year 2011	Year 2012	Year 2013	Year 2014
Oil Positions:				
Fixed Price Swaps:				
VNG				
Notional Volume (Bbls)	443,250	347,700	296,400	209,875
Fixed Price ($/Bbl)	$ 87.94	$ 90.03	$ 89.84	$ 94.37
ENP				
Notional Volume (Bbls)	523,775	947,940	1,295,750	1,168,000
Fixed Price ($/Bbl)	$ 79.48	$ 82.05	$ 88.95	$ 88.95
Consolidated				
Notional Volume (Bbls)	967,025	1,295,640	1,592,150	1,377,875
Fixed Price ($/Bbl)	$ 83.36	$ 84.19	$ 89.11	$ 89.78
Collars:				
VNG				
Notional Volume (Bbls)	•	45,750	45,625	•
Floor Price ($/Bbl)	$ •	$ 80.00	$ 80.00	$ •
Ceiling Price ($/Bbl)	$ •	$ 100.25	$ 100.25	$ •
ENP				
Notional Volume (Bbls)	525,600	274,500	•	•
Floor Price ($/Bbl)	$ 73.06	$ 68.33	$ •	$ •
Ceiling Price ($/Bbl)	$ 95.41	$ 81.12	$ •	$ •
Consolidated				
Notional Volume (Bbls)	525,600	320,250	45,625	•
Floor Price ($/Bbl)	$ 73.06	$ 70.00	$ 80.00	$ •
Ceiling Price ($/Bbl)	$ 95.41	$ 83.85	$ 100.25	$ •
Puts:				
ENP				
Notional Volume (Bbls)	803,000	552,660	•	•
Floor Price ($/Bbl)	$ 74.82	$ 65.83	$ •	$ •
Total Oil Positions:				
VNG				
Notional Volume (Bbls)	443,250	393,450	342,025	209,875
ENP				
Notional Volume (Bbls)	1,852,375	1,775,100	1,295,750	1,168,000
Consolidated				
Notional Volume (Bbls)	2,295,625	2,168,550	1,637,775	1,377,875

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

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

Interest Rate Risks

At December 31, 2010, we had debt outstanding of $585.5 million. The amount outstanding under our reserve-based credit facility at December 31, 2010 of $176.5 million is subject to interest at floating rates based on LIBOR. If the debt remains the same, a 10% increase in LIBOR would result in an estimated $0.1 million increase in annual interest expense after consideration of the interest rate swaps discussed below. There was no interest rate derivatives hedging the interest rates associated with the amount outstanding under our Term Loan at December 31, 2010 of $175.0 million. The amount outstanding under ENP's revolving credit facility at December 31, 2010 of $234.0 million is subject to floating market rates of interest that are linked to the Eurodollar rate. At this level of floating rate debt, if the Eurodollar rate increased 10%, we would incur an additional $0.2 million of interest expense per year.

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, 2010 (in thousands):

	Notional Amount	Fixed Libor Rates
Period:		
VNR		
January 1, 2011 to March 31, 2011	$ 20,000	2.08%
January 1, 2011 to December 10, 2012	$ 20,000	3.35%
January 1, 2011 to January 31, 2013	$ 20,000	2.38%
January 1, 2011 to January 31, 2013	$ 20,000	2.66%
August 6, 2012 to August 6, 2014	$ 25,000	2.09%
August 6, 2012 to August 5, 2015 (1)	$ 30,000	2.25%
ENP		
January 1, 2011 to January 31, 2011	$ 50,000	3.16%
January 1, 2011 to January 31, 2011	$ 25,000	2.97%
January 1, 2011 to January 31, 2011	$ 25,000	2.96%
January 1, 2011 to March 31, 2012	$ 50,000	2.42%

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index

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

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Vanguard Natural Resources, LLC as of December 31, 2010 and 2009 and the related consolidated statements of operations, comprehensive income, members' equity, and cash flows for each of the three years in the period ended December 31, 2010. 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, 2010 and 2009, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2010, 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 ASC 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 oil and natural gas 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, 2010, 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 8, 2011 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP

Houston, Texas
March 8, 2011

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

	2010	2009	2008
Revenues			
Oil, natural gas and natural gas liquids sales	$ 85,357	$ 46,035	$ 68,850
Gain (loss) on commodity cash flow hedges	(2,832)	(2,380)	269
Realized gain (loss) on other commodity derivative contracts	24,774	29,993	(6,552)
Unrealized gain (loss) on other commodity derivative contracts	(14,145)	(19,043)	39,029
Total revenues	93,154	54,605	101,596
Costs and expenses			
Lease operating expenses	18,471	12,652	11,112
Depreciation, depletion, amortization and accretion	22,231	14,610	14,910
Impairment of oil and natural gas properties	•	110,154	58,887
Selling, general and administrative expenses	10,134	10,644	6,715
Production and other taxes	6,840	3,845	4,965
Total costs and expenses	57,676	151,905	96,589
Income (loss) from operations	35,478	(97,300)	5,007
Other income (expense)			
Interest income	1	•	17
Interest expense	(5,766)	(4,276)	(5,491)
Realized loss on interest rate derivative contracts	(1,799)	(1,903)	(107)
Gain (loss) on acquisition of oil and natural gas properties	(5,680)	6,981	•
Unrealized gain (loss) on interest rate derivative contracts	(349)	763	(3,178)
Total other income (expense)	(13,593)	1,565	(8,759)
Net income (loss)	$ 21,885	$ (95,735)	$ (3,752)
Net income (loss) per Common and Class B units - basic & diluted	$ 1.00	$ (6.74)	$ (0.32)
Weighted average units outstanding:			
Common units – basic	21,500	13,791	11,374
Common units –diluted	21,538	13,791	11,374
Class B units – basic & diluted	420	420	420

See accompanying notes to consolidated financial statements.

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

	2010	2009
Assets		
Current assets		
Cash and cash equivalents	$ 1,828	$ 487
Trade accounts receivable, net	32,664	8,025
Derivative assets	24,115	16,190
Other receivables	1,614	2,224
Other currents assets	1,474	1,317
Total current assets	61,695	28,243
Oil and natural gas properties, at cost	1,312,107	399,212
Accumulated depletion, amortization and accretion	(248,704)	(226,687)
Oil and natural gas properties evaluated, net – full cost method	1,063,403	172,525
Other assets		
Derivative assets	6,129	5,225
Deferred financing costs	5,649	3,298
Goodwill	420,955	•
Other intangible assets	9,017	•
Other assets	1,903	1,409
Total assets	$1,568,751	$ 210,700
Liabilities and members' equity		
Current liabilities		
Accounts payable – trade	$ 2,250	$ 766
Accounts payable – oil and natural gas	11,340	2,299
Payables to affiliates	668	1,387
Deferred swap premium liability	1,739	1,334
Derivative liabilities	13,801	253
Phantom unit compensation accrual	179	4,299
Accrued ad valorem taxes	9,019	903
Accrued expenses	10,383	1,178
Term loan	175,000	•
Total current liabilities	224,379	12,419
Long-term debt	410,500	129,800
Derivative liabilities	35,034	2,036
Deferred swap premium liability	•	1,739
Asset retirement obligations	29,434	4,420
Other long term liabilities	11	•
Total liabilities	699,358	150,414
Commitments and contingencies (Note 9)		
Members' equity		
Members' capital, 29,666,039 and 18,416,173 common units issued and outstanding at December 31, 2010 and 2009, respectively	318,597	59,873
Class B units, 420,000 issued and outstanding at December 31, 2010 and 2009	5,166	5,930
Accumulated other comprehensive loss	(3,032)	(5,517)
Total VNR members' equity	320,731	60,286
Non-controlling interest in subsidiary	548,662	•
Total members' equity	869,393	60,286
Total liabilities and members' equity	$1,568,751	$ 210,700

See accompanying notes to consolidated financial statements.

Vanguard Natural Resources, LLC and Subsidiaries
Consolidated Statements of Members' Equity
For the Years Ended December 31, 2010, 2009 and 2008
(in thousands, except per unit data)

	Common Units	Common Units Amount	Class B Units	Class B Units Amount	Accumulated Other Comprehensive Loss	Non-controlling Interest	Total Members' Equity
Balance, January 1, 2008	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 oil and natural gas 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 loss	•	•	•	•	2,254	•	2,254
Balance, 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
Distributions to members ($0.525 per unit to unitholders of record February 5, 2010 and May 7, 2010 and $0.55 per unit to unitholders of record August 6, 2010 and November 5, 2010, respectively)	•	(45,747)	•	(903)	•	•	(46,650)
Issuance of common units, net of offering costs of $530	8,263	193,541	•	•	•	•	193,541
Issuance of common units in connection with Encore Acquisition	3,137	93,020	•	•	•	•	93,020
Redemption of common units	(150)	(3,651)	•	•	•	•	(3,651)
Unit-based compensation	•	(324)	•	139	•	•	(185)
Net income	•	21,885	•	•	•	•	21,885
Settlement of cash flow hedges in other comprehensive income	•	•	•	•	2,485	•	2,485
Non-controlling interest in subsidiary	•	•	•	•	•	548,662	548,662
Balance at December 31, 2010	29,666	$318,597	420	$5,166	$(3,032)	$548,662	$869,393

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)

	2010	2009	2008
Operating activities			
Net income (loss)	$ 21,885	$ (95,735)	$ (3,752)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	22,231	14,610	14,910
Impairment of oil and natural gas properties	•	110,154	58,887
Amortization of deferred financing costs	1,373	639	362
Unit-based compensation	847	2,483	3,577
Non-cash portion of phantom units granted to officers	179	393	•
Amortization of premiums paid on derivative contracts	1,950	3,502	4,493
Amortization of value on derivative contracts acquired	1,995	3,619	733
Unrealized (gains) losses on other commodity and interest rate derivative contracts	14,494	18,280	(35,851)
(Gain) loss on acquisitions of oil and natural gas properties	5,680	(6,981)	•
Changes in operating assets and liabilities:			
Trade accounts receivable	(1,844)	(1,942)	(2,208)
Payables to affiliates	610	(1,168)	(1,850)
Price risk management activities, net	(817)	94	(343)
Other receivables	(341)	539	(2,265)
Other current assets	(105)	(536)	(345)
Accounts payable	765	(410)	2,161
Accrued expenses	2,672	4,739	1,045
Other assets	3	(125)	•
Net cash provided by operating activities	71,577	52,155	39,554
Investing activities			
Encore acquisition, net of cash acquired	(298,620)	•	•
Additions to property and equipment	(198)	(57)	(74)
Additions to oil and natural gas properties	(15,277)	(4,960)	(18,174)
Acquisitions of oil and natural gas properties	(115,832)	(103,923)	(100,743)
Deposits and prepayments of oil and natural gas properties	(67)	(375)	(548)
Net cash used in investing activities	(429,994)	(109,315)	(119,539)
Financing activities			
Proceeds from borrowings	480,700	80,349	340,300
Repayment of debt	(259,000)	(85,549)	(242,700)
Proceeds from equity offerings, net	193,541	97,627	(54)
Redemption of common units	(3,651)	(4,305)	•
Distributions to members	(46,650)	(27,098)	(20,129)
Financing costs	(3,724)	(3,055)	(303)
Deferred offering costs	(37)	•	•
Purchases of units for issuance as unit-based compensation	(1,421)	(325)	(236)
Net cash provided by financing activities	359,758	57,644	76,878
Net increase (decrease) in cash and cash equivalents	1,341	484	(3,107)
Cash and cash equivalents, beginning of year	487	3	3,110
Cash and cash equivalents, end of year	$ 1,828	$ 487	$ 3

Supplemental cash flow information:			
Cash paid for interest	$ 4,430	$ 3,894	$ 5,040
Non-cash financing and investing activities:			
Asset retirement obligations	$ 558	$ 2,163	$ 1,882
Derivatives assumed in acquisition of oil and natural gas properties	$ •	$ 4,128	$ 2,468
Deferred swap liability	$ •	$ 3,072	$ •
Non-monetary exchange of oil and natural gas properties	$ •	$ 2,660	$ •
Issuance of common units for acquisition of oil and natural gas properties	$ •	$ •	$ 21,360
Transfer of deposit for acquisition of oil and natural gas properties	$ •	$ •	$ 7,830
Encore Acquisition:			
Assets acquired:			
Oil and natural gas properties	$ 786,524	$ •	$ •
Goodwill	$ 420,955	$ •	$ •
Other long-term assets	$ 9,731	$ •	$ •
Long-term debt assumed	$ 234,000	$ •	$ •
Asset retirement obligations assumed	$ 25,092	$ •	$ •
Common units issued	$ 93,020	$ •	$ •
Non-controlling interest in subsidiary	$ 548,662	$ •	$ •

See accompanying notes to consolidated financial statements.

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

	2010	2009	2008
Net income (loss)	$ 21,885	$ (95,735)	$ (3,752)
Net income (losses) from derivative contracts:			
Unrealized mark-to-market gains arising during the period	•	•	2,747
Reclassification adjustments for settlements	2,485	2,288	(493)
Other comprehensive income	2,485	2,288	2,254
Comprehensive income (loss)	$ 24,370	$ (93,447)	$ (1,498)

See accompanying notes to consolidated financial statements.

Description of the Business:

Vanguard Natural Resources, LLC is a publicly traded limited liability company focused on the acquisition and development of mature, long-lived oil and natural gas properties in the United States. We own a 100% controlling interest, through certain of our subsidiaries, in properties and oil and natural gas reserves located in four operating areas:

- the Permian Basin in west Texas and New Mexico;
- south Texas;
- the southern portion of the Appalachian Basin, primarily in southeast Kentucky and northeast Tennessee; and
- Mississippi.

In addition, we own an approximate 46.7% aggregate controlling interest through our subsidiary, Encore Energy Partners, LP ("ENP"), in properties and oil and natural gas reserves located in four operating areas:

- the Permian Basin in west Texas and New Mexico;
- the Big Horn Basin in Wyoming and Montana;
- the Williston Basin in North Dakota and Montana; and
- the Arkoma Basin in Arkansas and Oklahoma.

References in this report to (1) "us," "we," "our," "the Company," "Vanguard" or "VNR" are to Vanguard Natural Resources, LLC and its subsidiaries, including Vanguard Natural Gas, LLC, Trust Energy Company, LLC ("TEC"), VNR Holdings, LLC ("VNRH"), Ariana Energy, LLC ("Ariana Energy"), Vanguard Permian, LLC ("Vanguard Permian"), VNR Finance Corp. ("VNRF"), Encore Energy Partners GP LLC ("ENP GP"), Encore Energy Partners LP ("ENP"), Encore Energy Partners Operating LLC ("OLLC"), Encore Energy Partners Finance Corporation ("ENPF"), Encore Clear Fork Pipeline LLC ("ECFP") 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.

On December 31, 2010, we completed an acquisition pursuant to a Purchase Agreement with Denbury Resources Inc. ("Denbury"), Encore Partners GP Holdings LLC, Encore Partners LP Holdings LLC and Encore Operating, L.P. (collectively, the "Encore Selling Parties" and, together with Denbury, the "Selling Parties") to acquire (the "Encore Acquisition" or "Encore") all of the member interest in ENP GP, the general partner of ENP and 20,924,055 common units representing limited partnership interests in ENP (the "ENP Units"), representing a 46.7% aggregate equity interest in ENP. As consideration for the purchase, we paid $300.0 million in cash and paid $80.0 million in stock by issuing 3,137,255 VNR common units, at an agreed upon price of $25.50 per unit, valued at the closing price of $29.65 at December 31, 2010.

In connection with closing of the Encore Acquisition, VNG entered into a Second Amended and Restated Administrative Services Agreement, dated December 31, 2010, with ENP, ENP GP, Encore Operating, L.P. ("Encore Operating"), OLLC and Denbury (the "Services Agreement"). The Services Agreement was amended solely to add VNG as a party and provide for VNG to assume the rights and obligations of Encore Operating and Denbury under the previous administrative services agreement going forward.

Pursuant to the Services Agreement, VNG will provide certain general and administrative services to ENP, ENP GP and OLLC (collectively, the "ENP Group") in exchange for a quarterly fee of $2.06 per barrel of oil equivalent of the ENP Group's total net oil and gas production for the most recently-completed quarter, which fee is paid by ENP (the "Administrative Fee"). The Administrative Fee is subject to certain index-related adjustments on an annual basis. ENP also is obligated to reimburse VNG for all third-party expenses it incurs on behalf of the ENP Group. These terms are identical to the terms under which Denbury and Encore Operating provided administrative services to the ENP Group prior to the second amendment and restatement of the Services Agreement.

As the acquisition was completed on December 31, 2010, no results of operations were included in the consolidated statement of operations for the year ended December 31, 2010. The fair value of the assets and liabilities we acquired on December 31, 2010 in the Encore Acquisition and cash flows associated with the transaction were included in the consolidated balance sheet as of December 31, 2010 and the statement of cash flows for the year ended December 31, 2010, respectively.

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, 2010, 2009 and 2008 include the accounts of VNR and its subsidiaries. As of December 31, 2010, we consolidated ENP as we have the ability to control the operating and financial decisions and policies of ENP through our ownership of ENP GP and reflected the non-controlling interest as a separate element of members' equity on our consolidated balance sheet.

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) ***Cash Equivalents:***

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

(c) ***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.

(d) ***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.

(e) ***Oil and Natural Gas Properties:***

The full cost method of accounting is used to account for oil and natural gas properties. Under the full cost method, substantially all costs incurred in connection with the acquisition, development and exploration of oil, natural gas and natural gas liquids 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.

Capitalized costs are limited to a ceiling based on the present value of future net revenues using the 12-month unweighted average of first-day-of-the-month price (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 oil and natural gas derivative contracts that have been recorded in other comprehensive income. We recorded a non-cash ceiling test impairment of oil and natural gas 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 oil and natural gas prices based upon the 12-month average price, we recorded an additional 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 oil and natural gas properties for the year ended December 31, 2008 of $58.9 million as a result of a decline in oil and natural gas prices at the measurement date. This impairment was calculated based on year end prices of $5.71 per MMBtu for natural gas and $41.00 per barrel of crude oil. No ceiling test impairment was required during 2010.

When we sell or convey interests in oil and natural gas properties, we reduce oil and natural gas reserves for the amount attributable to the sold or conveyed interest. We do not recognize a gain or loss on sales of oil and natural gas 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.

(f) ***Business Combinations:***

We account for business combinations under Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 805, "Business Combinations." We recognize and measure in our financial statements the fair value of all identifiable assets acquired, the liabilities assumed, any non-controlling interests in the acquiree and the goodwill acquired in all transactions in which control of one or more businesses is obtained.

(g) ***Goodwill and Other Intangible Assets:***

We account for goodwill and other intangible assets under the provisions of the "*Goodwill and Other Intangible Assets*" topic of the FASC. Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in business combinations. Goodwill is not amortized, but is tested for impairment annually on October 1 or whenever indicators of impairment exist. The goodwill test is performed at the reporting unit level. We have determined that we have two reporting units, which are Vanguard's historical oil and natural gas operations in the United States and ENP's oil and natural gas operations in the United States. At December 31, 2010, all goodwill was assigned to the reporting unit comprised of ENP's oil and natural gas operations in the United States. If indicators of impairment are determined to exist, an impairment charge is recognized for the amount by which the carrying value of goodwill exceeds its implied fair value.

We utilize both a market capitalization and an income approach to determine the fair value of our reporting units. The primary component of the income approach is the estimated discounted future net cash flows expected to be recovered from the reporting unit's oil and natural gas properties. Our analysis concluded that there was no impairment of goodwill as of December 31, 2010. Significant decreases in the prices of oil and natural gas or significant negative reserve adjustments from the December 31, 2010 assessment could change our estimates of the fair value of our reporting units and could result in an impairment charge.

Intangible assets with definite useful lives are amortized over their estimated useful lives. We evaluate the recoverability of intangible assets with definite useful lives whenever events or changes in circumstances indicate that the carrying value of the asset may not be fully recoverable. An impairment loss exists when the estimated undiscounted cash flows expected to result from the use of the asset and its eventual disposition are less than its carrying amount.

Encore is a party to a contract allowing it to purchase a certain amount of natural gas at a below market price for use as field fuel. As of December 31, 2010, the gross carrying value of this contact was $9.0 million. The carrying value is shown as “Other intangibles” on the accompanying consolidated balance sheets and will be amortized on a straight-line basis over the estimated life of the field. The estimated aggregate amortization expense for each of the five succeeding fiscal years is $0.2 million per year.

(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 oil and natural gas wells and decommissioning of ENP’s Elk Basin gas plant. 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 oil and natural gas 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 oil and natural gas properties, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. 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 oil, natural gas and natural gas liquids are recognized when oil, natural gas and natural gas liquids 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 oil, natural gas and natural gas liquids 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 oil, natural gas or natural gas liquid, and prevailing supply and demand conditions, so that the price of the oil, natural gas and natural gas liquid fluctuates to remain competitive with other available oil, natural gas and natural gas liquid supplies. To the extent actual volumes and prices of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and prices for those properties are estimated and recorded as “Trade accounts receivable, net” in the accompanying consolidated balance sheets.

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, 2010 and 2009.

(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, 2010 and 2009, the cash and cash equivalents were concentrated in four and three financial institutions, respectively. 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 oil, natural gas and natural gas liquids sales for the years ended December 31:

	2010	2009	2008
Seminole Energy Services	20%	35%	52%
Plains Marketing L.P.	19%	7%	7%
Shell Trading (US) Company	11%	2%	1%
Osram Sylvania, Inc.	5%	9%	15%
BP Energy Company	•	•	10%

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 oil, natural gas and natural gas liquids reserves and related cash flow estimates used in impairment tests of oil and natural gas properties, the fair value of assets and liabilities acquired in business combinations, goodwill, derivative contracts, asset retirement obligations, accrued oil, natural gas and natural gas liquids 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 financing arrangements to hedge price risk associated with a portion of our oil and natural gas 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, Houston Ship Channel, West Texas ("Waha Index"), El Paso Natural Gas Company (Permian Basin) or Colorado Interstate Gas Company (Rocky Mountains) for natural gas production and the West Texas Intermediate Light Sweet for oil production. In addition, we sell calls or provide options to counterparties under swaption agreements to extend the swaps into subsequent years. 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 VNR, the book basis of its net assets exceeded the net tax basis by $32.2 million and $38.0 million at December 31, 2010 and 2009, 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 $0.2 million during the year ended December 31, 2010, and $0.1 million during each of the years ended December 31, 2009 and 2008, and a deferred tax asset of $0.1 million during each of the years ended December 31, 2010 and 2009. A charge of $0.2 million and a benefit of $0.2 million are included in our consolidated statements of operations for the years ended December 31, 2010 and 2009, respectively, as a component of production and other taxes. For the year ended December 31, 2008, a charge of $0.3 million is included in our consolidated statements of operations.

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. 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 oil and natural gas 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 oil and natural gas 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, after consideration of purchase price adjustments of approximately $1.8 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 oil and natural gas 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:		
Oil and natural gas 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 oil and natural gas 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 oil and natural gas properties located in Ward County, Texas in the Permian Basin from private sellers, referred to as the "Ward County acquisition." This transaction had an effective date of October 1, 2009 and was closed on December 2, 2009 for $55.0 million. This acquisition was initially funded with borrowings under our reserve-based credit facility with borrowings being reduced by $40.3 million shortly thereafter with the proceeds from a 2.6 million common unit offering. In an effort to support stable cash flows from this transaction, we entered into crude oil swaps based on NYMEX pricing for approximately 90% of the estimated oil production from existing producing wells in the acquired properties for the period beginning January 2010 through December 2013.

In accordance with the guidance contained within ASC Topic 805, the measurement of the fair value at acquisition date of the assets acquired in the Ward County acquisitions as compared to the fair value of consideration transferred, adjusted for purchase price adjustments, resulted in a gain of $1.1 million, calculated in the following table. The gain resulted from the changes in oil and natural gas 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:		
Oil and natural gas 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 oil and natural gas properties	$	1,103

On April 30, 2010, we entered into a definitive agreement with a private seller for the acquisition of certain oil and natural gas properties located in Mississippi, Texas and New Mexico. We refer to this acquisition as the "Parker Creek acquisition." The purchase price for said assets was $113.1 million with an effective date of May 1, 2010. We completed this acquisition on May 20, 2010. The adjusted purchase price of $114.3 million considered final purchase price adjustments of approximately $1.2 million. The purchase price was funded from the approximate $71.5 million in net proceeds from our May 2010 equity offering and with borrowings under the Company's existing reserve-based credit facility. In conjunction with the acquisition, we entered into crude oil hedges covering approximately 56% of the estimated production from proved producing reserves through 2013 at a weighted average price of $91.70 per barrel.

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

	(in thousands)
Fair value of assets and liabilities acquired:	
Oil and natural gas properties	$ 107,598
Other assets	1,505
Asset retirement obligations	(500)
Total fair value of assets and liabilities acquired	108,603
Fair value of consideration transferred	114,283
Loss on acquisition of oil and natural gas properties	$ (5,680)

On November 16, 2010, we entered into a Purchase Agreement with Denbury Resources Inc. ("Denbury"), Encore Partners GP Holdings LLC, Encore Partners LP Holdings LLC and Encore Operating, L.P. (collectively, the "Encore Selling Parties" and, together with Denbury, the "Selling Parties") to acquire (the "Encore Acquisition" or "Encore") all of the member interest in ENP GP, the general partner of ENP and 20,924,055 common units representing limited partnership interests in ENP (the "ENP Units"), representing a 46.7% aggregate equity interest in ENP. As consideration for the purchase, we paid $300.0 million in cash and paid $80.0 million in stock by issuing 3,137,255 VNR common units, at an agreed upon price of $25.50 per unit, valued at the closing price of $29.65 at December 31, 2010. We completed this acquisition on December 31, 2010.

The acquisition was accounted for under the acquisition method of accounting in accordance with ASC 805 relating to "Business Combinations". The acquisition method requires the assets and liabilities acquired to be recorded at their fair values at the date of acquisition. No results of operations were recorded in the consolidated statement of operations for the year ended December 31, 2010. Transaction costs related to the acquisition were approximately $3.6 million, which were expensed as incurred and recorded as "Selling, general and administrative expenses" in the consolidated statement of operations for the year ended December 31, 2010. The preliminary estimate of fair values as of December 31, 2010 is as follows (in thousands):

Consideration and non-controlling interest	
Cash payment to acquire Encore Interests	$ 300,000
Market value of Vanguard's common units issued to Denbury(1)	93,020
Market value of non-controlling interest of Encore(2)	548,662
Consideration and non-controlling interest of Encore	$ 941,682
Add: fair value of liabilities assumed	
Accounts payable and accrued liabilities	$ 18,048
Natural gas and oil payable	1,730
Current derivative liabilities	11,122
Other current liabilities	1,228
Long-term debt	234,000
Asset retirement obligations	24,385
Long-term derivative liabilities	25,331
Long-term deferred tax liability	11
Amount attributable to liabilities assumed	$ 315,855
Less: fair value of assets acquired	
Cash	$ 1,380
Trade and other receivables	22,795
Current derivative assets	10,196
Other current assets	470
Natural gas and oil properties • proved	786,524
Long-term derivative assets	5,486
Other long-term assets	9,731
Amount attributable to assets acquired	$ 836,582
Goodwill	$ 420,955

(1) Approximately 3.1 million Vanguard common units at $29.65 per unit issued to Denbury to acquire the Encore Interests. The per unit price is the closing price of Vanguard's common units at December 31, 2010.

(2) Represents approximate market value of the non-controlling interest of Encore (based on 24.4 million Encore common units outstanding as of December 31, 2010) at $22.47 per Encore common unit (closing price as of December 31, 2010).

The following unaudited pro forma results for the years ended December 31, 2010, 2009 and 2008 show the effect on our consolidated results of operations as if (1) the Parker Creek and Encore acquisitions had occurred on January 1, 2010 and January 1, 2009, (2) the Sun TSH and Ward County acquisitions had occurred on January 1, 2009 and January 1, 2008 and (3) the Dos Hermanos and Permian Basin acquisitions had occurred on January 1, 2008. The gains recognized on the Sun TSH and Ward County acquisitions of $5.9 and $1.1 million, respectively, were excluded from the pro forma results for the years ended December 31, 2009 and 2008 and the loss recognized on the Parker Creek acquisition of $5.7 million was excluded from the pro forma results for the years ended December 31, 2010 and 2009. The pro forma results reflect the results of combining our statement of operations with the revenues and direct operating expenses of the oil and gas properties acquired in the Permian Basin, Dos Hermanos, Sun TSH, Ward County and Parker Creek acquisitions adjusted for (1) assumption of asset retirement obligations and accretion expense for the properties acquired, (2) depletion expense applied to the adjusted basis of the properties acquired using the acquisition method of accounting, (3) interest expense on additional borrowings necessary to finance the acquisitions, (4) non-cash impairment charge, and (5) the impact of additional common units issued in connection with these acquisitions. Additionally, the pro forma results reflect the results of combining our statement of operations with Encore's adjusted for (1) the conversion of Encore's method of accounting for oil and natural gas properties from the successful efforts method of accounting to the full cost method of accounting, (2) the interest expense on additional borrowings necessary to finance the acquisition, (3) the impact of additional common units issued in connection with the acquisition and (4) the allocable portion of Encore's historical net income (loss) and the impact of adjustments (1)-(2) to earnings relating to the non-controlling interest of Encore. The pro forma information is based upon these assumptions, and is not necessarily indicative of future results of operations:

	Year Ended December 31,		
	2010 Pro forma	**2009 Pro forma**	**2008 Pro forma**
		(in thousands, except per unit amounts) (unaudited)	
Total revenues	$ 269,112	$ 185,259	$ 151,956
Net income (loss)	$ 39,897	$ (149,750)	$ 36,218
Net income (loss) attributable to non-controlling interest	11,294	(22,946)	•
Net income (loss) attributable to VNR	$ 28,603	$ (126,804)	$ 36,218
Net income (loss) per unit:			
Common & Class B units – basic & diluted	$ 0.96	$ (4.25)	$ 1.92

The amount of revenue and excess of revenues over direct operating expenses included in our 2010, 2009 and 2008 consolidated statements of operations for each of our acquisitions mentioned above are shown in the table that follows. Direct operating expenses include lease operating expenses, selling, general and administrative expenses and production and other taxes.

	Year Ended December 31,		
	2010	**2009**	**2008**
		(in thousands)	
Permian Basin			
Revenues	$ 17,647	$ 14,372	$ 21,833
Excess of revenues over direct operating expenses	$ 12,037	$ 9,801	$ 15,869
Dos Hermanos			
Revenues	$ 4,922	$ 4,622	$ 3,999
Excess of revenues over direct operating expenses	$ 2,311	$ 1,586	$ 1,598
Sun TSH			
Revenues	$ 11,740	$ 4,739	$ •
Excess of revenues over direct operating expenses	$ 6,723	$ 3,460	$ •
Ward County			
Revenues	$ 15,438	$ 1,059	$ •
Excess of revenues over direct operating expenses	$ 9,631	$ 640	$ •
Parker Creek			
Revenues	$ 11,472	$ •	$ •
Excess of revenues over direct operating expenses	$ 9,722	$ •	$ •

3. Accounts Receivable and Allowance for Doubtful Accounts

In May 2007, we established an approximate $1.0 million allowance for a loss on the entire amount due from a customer which filed for protection under Chapter 11 of the Bankruptcy Code. 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. Long-Term Debt

Our financing arrangements consisted of the following:

Description	Interest Rate	Maturity Date	Amount Outstanding December 31, 2010	2009
			(in thousands)	
Senior secured reserve-based credit facility	Variable (1)	October 1, 2012	$ 176,500	$ 129,800
Term Loan	Variable (2)	December 31, 2011	175,000	•
ENP's revolving credit facility	Variable (3)	March 7, 2012	234,000	•
Total debt			585,500	129,800
Less: current obligations			(175,000)	•
Total long term debt			$ 410,500	$ 129,800

(1) Variable interest rate was 3.0% and 2.7% at December 31, 2010 and 2009, respectively.
(2) Variable interest rate was 5.77% at December 31, 2010.
(3) Weighted average interest rate was 2.79% at December 31, 2010.

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 oil, natural gas and natural gas liquids reserves of the Company. The reserve-based credit facility is secured by a first lien security interest in all of the Company's oil and natural gas properties. Additional borrowings were made in January 2008 pursuant to the acquisition of oil and natural gas properties in the Permian Basin. In February 2008, our reserve-based credit facility was amended and restated to extend the maturity from January 3, 2011 to March 31, 2011, increase the maximum facility amount from $200.0 million to $400.0 million, increase our borrowing base from $110.5 million to $150.0 million and add two additional financial institutions as lenders, Wachovia Bank, N.A. and The Bank of Nova Scotia. In May 2008, our reserve-based credit facility was amended in response to a potential acquisition that ultimately did not occur. As a result, none of the provisions included in this amendment went into effect.

In July 2008 an additional $30.0 million was borrowed to fund a portion of the cash consideration paid in the Dos Hermanos acquisition and in October 2008, we amended our reserve-based credit facility, which set our borrowing base under the facility at $175.0 million pursuant to our semi annual redetermination and added a new lender, BBVA Compass Bank. In February 2009, our reserve-based credit facility was amended to allow us to repurchase up to $5.0 million of our own units. In May 2009, our borrowing base was set at $154.0 million pursuant to our semi-annual redetermination. In June 2009, a fourth amendment to our reserve-based credit facility was entered into which temporarily increased the percentage of outstanding indebtedness for which interest rate derivatives could be used. The percentage was increased from 75% to 85% but was to revert back to 75% in one year at June 2010. In August 2009, our reserve-based credit facility was amended and restated to (1) extend the maturity from March 31, 2011 to October 1, 2012, (2) increase our borrowing base from $154.0 million to $175.0 million, (3) increase our borrowing costs, (4) permanently allow 85% of our outstanding indebtedness to be covered under interest rate derivatives, and (5) add two financial institutions as lenders, Comerica Bank and Royal Bank of Canada. On October 1, 2009, we entered into the First Amendment to our Second Amended and Restated Credit Agreement, which reduced our borrowing base under the reserve-based credit facility from $175.0 million to $170.0 million pursuant to our semi-annual redetermination and changed the definition of majority lenders from 75% to 66.67%. All other terms under the reserve-based credit facility remained the same. In December 2009, our borrowing base was increased from $170.0 million to $195.0 million pursuant to an interim redetermination requested by the Company due to the Ward County acquisition. In June 2010, we entered into the Second Amendment to Second Amended and Restated Credit Agreement, which (1) increased the borrowing base to $240 million, (2) allows us to enter into commodity price hedges with respect to the acquired production upon signing a purchase and sale agreement, (3) added a new lender, Credit Agricole Corporate and Investment Bank, and (4) allows us to hedge up to 85% of the projected oil and gas production from total proved reserves. Previously, our hedging was limited to 95% of the projected oil and gas production from proved developed producing reserves. In November 2010, our borrowing base under the reserve-based credit facility was reduced from $240.0 million to $225.0 million pursuant to our semi-annual redetermination. Also in November 2010, in connection with the Encore Acquisition, we entered into the Third Amendment to the Second Amended and Restated Credit Agreement to provide for certain amendments and modifications to allow us to incur indebtedness under, and grant the related security interests for, the Term Loan discussed below. Such amendments and modifications include the granting of a second priority lien on VNG's interests in ENP GP and the ENP Units. In addition to the existing first priority liens on the assets of VNG and its subsidiaries, amounts outstanding under the reserve-based credit facility will also be secured by a second priority lien on VNG's interest in ENP GP and the ENP Units. In December 2010, we entered into the Fourth Amendment to Second Amended and Restated Credit Agreement, which contains certain amendments necessary to exclude ENP GP's pledge of the general partners interests issued by ENP that it owns as collateral securing the loans and other extensions of credit made to VNG pursuant to the Second Amended and Restated Credit Agreement. Additionally, the Fourth Amendment clarifies the amounts guaranteed by subsidiaries of VNG pursuant to guaranty agreements previously delivered by such subsidiaries. On December 31, 2010 there were $176.5 million of outstanding borrowings and $48.5 million of borrowing capacity under the reserve-based credit facility.

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, 2010 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 September 30, 2010, we were in an over hedged position in 2010 natural gas volumes as we had hedged 85.9% of our expected natural gas production for the remainder of 2010, which is in excess of the maximum permitted by the credit agreement of 85%. We were in compliance with all of our other debt covenants at September 30, 2010. Our lenders issued a waiver in November 2010 for this over hedged position in 2010 natural gas volumes. Additionally, we received a waiver through April 2011 for an over hedged position in interest rate derivatives which occurred in October 2010 as a result of the reduction of outstanding borrowings utilizing the net proceeds of the October common unit offering. The credit agreement limits the amount of outstanding debt to be hedged to no greater than 85% of the actual outstanding balance. At December 31, 2010, we were in compliance with all of 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.

Term Loan

Concurrent with the Encore Acquisition, VNG entered into a $175.0 million Term Loan with BNP Paribas to fund a portion of the consideration for the acquisition.

Borrowings under the Term Loan are comprised entirely of ABR Loans or Eurodollar Loans as VNG may request. Interest on ABR Borrowings under the Term Loan is payable quarterly on the last day of each March, June, September and December and accrues at a rate per annum equal to 6.50% plus the greater of (a) the prime rate in effect on such day, (b) the Federal Funds Effective Rate in effect on such day plus ½ of 1%, and (c) the Adjusted LIBO Rate in effect on such day plus 2%. Interest on Eurodollar Borrowings is payable on the last day of the interest period applicable to such borrowing, and in the case of a Eurodollar Borrowing with an interest period of more than three months' duration, each day prior to the last day of such interest period that occurs at intervals of three months' duration after the first day of such interest period. Amounts outstanding under the Term Loan may be prepaid prior to maturity, together with all accrued and unpaid interest relating to the amount prepaid, without prepayment penalty. The Term Loan contains various covenants, including restrictions on liens, restrictions on incurring other indebtedness without the lenders' consent and restrictions on entering into certain transactions. The Term Loan matures the earlier of the first anniversary of the effective date (December 31, 2011) or the date following both the completion of any acquisition by Vanguard of the remainder of ENP and VNG's execution and delivery of a new or amended and restated revolving credit facility replacing VNG's current reserve-based credit facility.

Amounts outstanding under the Term Loan are secured by a second priority lien on all assets of VNG and its subsidiaries securing VNG's current reserve-based credit facility (other than VNG's interest in ENP GP and the ENP Units) and a first priority lien on VNG's interest in ENP GP and the ENP Units.

Our Term Loan contains a number of customary covenants that among other things require us to maintain certain financial ratios. At December 31, 2010, we believe that we are in compliance with the terms of our Term Loan.

ENP's Revolving Credit Facility

ENP is a party to a five-year credit agreement dated March 7, 2007 (as amended, the "ENP Credit Agreement"). The ENP Credit Agreement matures on March 7, 2012. In December 2010, ENP amended the ENP Credit Agreement to, among other things, amend the definition of "Change of Control" to eliminate references to the Selling Parties and include change of control triggers upon (1) the failure of Vanguard to continue to control ENP's general partner, (2) the acquisition by any person or group, directly or indirectly, of equity interests representing more than 35% of the total voting power in Vanguard, or (3) the occupation of a majority of the seats on the board of managers of Vanguard by persons who were neither (x) nominated by the board of managers of Vanguard nor (y) appointed by managers so nominated. This amendment also modifies the covenant governing transactions with affiliates to eliminate all references to the Selling Parties and instead reference transactions with VNG and its subsidiaries.

The ENP Credit Agreement provides for revolving credit loans to be made to ENP from time to time and letters of credit to be issued from time to time for the account of ENP or any of its restricted subsidiaries. The aggregate amount of the commitments of the lenders under the ENP Credit Agreement is $475 million. Availability under the ENP Credit Agreement is subject to a borrowing base of $375 million, which is redetermined semi-annually and upon requested special redeterminations. On December 31, 2010, there were $234 million of outstanding borrowings and $141 million of borrowing capacity under the ENP Credit Agreement.

ENP incurs a quarterly commitment fee at a rate of 0.5 % per year on the unused portion of the ENP Credit Agreement. Obligations under the ENP Credit Agreement are secured by a first-priority security interest in substantially all of ENP's proved oil and natural gas reserves and in the equity interests of ENP and its restricted subsidiaries. In addition, obligations under the ENP Credit Agreement are guaranteed by us and ENP's restricted subsidiaries. Obligations under the ENP Credit Agreement are non-recourse to Vanguard and its restricted subsidiaries.

Loans under the ENP Credit Agreement are subject to varying rates of interest based on (1) outstanding borrowings in relation to the borrowing base and (2) whether the loan is a Eurodollar loan or a base rate loan. Such loans bear interest at the applicable rate plus the applicable margin indicated in the following table:

Ratio of Outstanding Borrowings to Borrowing Base	<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%

The “Eurodollar rate” for any interest period (either one, two, three, or six months, as selected by us) is the rate equal to the British Bankers Association LIBOR for deposits in dollars for a similar interest period. The “Base Rate” is calculated as the highest of: (1) the annual rate of interest announced by Bank of America, N.A. as its “prime rate” (2) the Federal Funds Effective Rate plus 0.5 %; or (3) except during a “LIBOR Unavailability Period,” the Eurodollar rate (for dollar deposits for a one-month term) for such day plus 1.0 %.

ENP’s Credit Agreement contains a number of customary covenants that requires ENP to maintain certain financial ratios, limits ENP’s 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 and engage in certain asset dispositions, including a sale of all or substantially all of the ENP’s assets. As of December 31, 2010, ENP was in compliance with all covenants of the ENP Credit Agreement.

5. Price and Interest Rate Risk Management Activities

We have entered into derivative contracts with counterparties that are lenders under our financing arrangements to hedge price risk associated with a portion of our oil and natural gas 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, Houston Ship Channel, West Texas (“Waha Index”), El Paso Natural Gas Company (Permian Basin) or Colorado Interstate Gas Company (Rocky Mountains) for natural gas production and the West Texas Intermediate Light Sweet for oil production. In addition, we sell calls or provide options to counterparties under swaption agreements to extend the swaps into subsequent years. Under put option agreements, we pay the counterparty an option premium, equal to the fair value of the option at the purchase date. At settlement date we receive the excess, if any, of the fixed floor over floating rate. Under collar contracts, we pay the counterparty if the market price is above the ceiling price and the counterparty pays us if the market price is below the floor price on a notional quantity. Put options for natural gas are settled based on the NYMEX price for natural gas at Henry Hub and collars are settled based on a market index selected by us at inception of the contract. We also enter into fixed LIBOR interest rate swap agreements with certain counterparties that are lenders under financing arrangements, 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.

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.

In May 2010, in connection with the Parker Creek acquisition, we entered into crude oil hedges covering approximately 56% of the estimated production from proved producing reserves through 2013 at a weighted average price of $91.70 per barrel.

At December 31, 2010, the Company had open commodity derivative contracts covering our anticipated future production as follows:

Swap Agreements

	Gas		Oil	
Contract Period	**MMBtu**	**Weighted Average Fixed Price**	**Bbls**	**WTI Price**
VNG				
January 1, 2011 – December 31, 2011	3,328,312	$ 7.83	443,250	$ 87.94
January 1, 2012 – December 31, 2012	•	$ •	347,700	$ 90.03
January 1, 2013 – December 31, 2013	•	$ •	296,400	$ 89.84
January 1, 2014 – December 31, 2014	•	$ •	209,875	$ 94.37
ENP				
January 1, 2011 – December 31, 2011	3,723,730	$ 6.06	523,775	$ 79.48
January 1, 2012 – December 31, 2012	3,367,932	$ 5.75	947,940	$ 82.05
January 1, 2013 – December 31, 2013	2,993,000	$ 5.10	1,295,750	$ 88.95
January 1, 2014 – December 31, 2014	•	$ •	1,168,000	$ 88.95
Consolidated				
January 1, 2011 – December 31, 2011	7,052,042	$ 6.89	967,025	$ 83.36
January 1, 2012 – December 31, 2012	3,367,932	$ 5.75	1,295,640	$ 84.19
January 1, 2013 – December 31, 2013	2,993,000	$ 5.10	1,592,150	$ 89.11
January 1, 2014 – December 31, 2014	•	$ •	1,377,875	$ 89.78

Swaptions

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

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

Collars

	Gas			Oil		
Production Period	MMBtu	Floor	Ceiling	Bbls	Floor	Ceiling
VNG						
January 1, 2011 – December 31, 2011	1,933,500	$ 7.34	$ 8.44	•	$ •	$ •
January 1, 2012 – December 31, 2012	•	$ •	$ •	45,750	$ 80.00	$ 100.25
January 1, 2013 – December 31, 2013	•	$ •	$ •	45,625	$ 80.00	$ 100.25
ENP						
January 1, 2011 – December 31, 2011	•	$ •	$ •	525,600	$ 73.06	$ 95.41
January 1, 2012 – December 31, 2012	•	$ •	$ •	274,500	$ 68.33	$ 81.12
Consolidated						
January 1, 2011 – December 31, 2011	1,933,500	$ 7.34	$ 8.44	525,600	$ 73.06	$ 95.41
January 1, 2012 – December 31, 2012	•	$ •	$ •	320,250	$ 70.00	$ 83.85
January 1, 2013 – December 31, 2013	•	$ •	$ •	45,625	$ 80.00	$ 100.25

Puts

	Gas		Oil	
Contract Period	MMBtu	Weighted Average Fixed Price	Bbls	WTI Price
ENP				
January 1, 2011 – December 31, 2011	1,240,270	$ 6.31	803,000	$ 74.82
January 1, 2012 – December 31, 2012	328,668	$ 6.76	552,660	$ 65.83

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, 2010, the Company had open interest rate derivative contracts as follows (in thousands):

	Notional Amount		Fixed Libor Rates
Period:			
VNR			
January 1, 2011 to March 31, 2011	$	20,000	2.08%
January 1, 2011 to December 10, 2012	$	20,000	3.35%
January 1, 2011 to January 31, 2013	$	20,000	2.38%
January 1, 2011 to January 31, 2013	$	20,000	2.66%
August 6, 2012 to August 6, 2014	$	25,000	2.09%
August 6, 2012 to August 5, 2015 (1)	$	30,000	2.25%
ENP			
January 1, 2011 to January 31, 2011	$	50,000	3.16%
January 1, 2011 to January 31, 2011	$	25,000	2.97%
January 1, 2011 to January 31, 2011	$	25,000	2.96%
January 1, 2011 to March 31, 2012	$	50,000	2.42%

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

Balance Sheet Presentation

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

	December 31,			
	2010		2009	
	(in thousands)			
Assets:				
Commodity derivatives	$	33,435	$	34,753
Interest rate swaps		97		•
	$	33,532	$	34,753
Liabilities:				
Commodity derivatives	$	(48,008)	$	(13,405)
Interest rate swaps		(4,115)		(2,222)
	$	(52,123)	$	(15,627)

By using derivative instruments to economically hedge exposures to changes in commodity prices and interest rates, we expose ourselves to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes us, which creates credit risk. Our counterparties are participants in our reserve-based credit facility (See Note 4. *Long-Term Debt* for further discussion) which is secured by our oil and natural gas 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 $33.5 million at December 31, 2010.

We minimize the credit risk in derivative instruments by: (i) entering into derivative instruments only with counterparties that are also lenders in our reserve-based credit facility and (ii) monitoring the creditworthiness of our counterparties on an ongoing basis. In accordance with our standard practice, our commodity and interest rate swap derivatives are subject to counterparty netting under agreements governing such derivatives and therefore the risk of such loss is somewhat mitigated as of December 31, 2010.

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:

	2010	2009	2008
		(in thousands)	
Realized gains (losses):			
Other commodity derivatives	$ 24,774	$ 29,993	$ (6,552)
Interest rate swaps	(1,799)	(1,903)	(107)
	$ 22,975	$ 28,090	$ (6,659)
Unrealized gains (losses):			
Other commodity derivatives	$ (14,145)	$ (19,043)	$ 39,029
Interest rate swaps	(349)	763	(3,178)
	$ (14,494)	$ (18,280)	$ 35,851
Total gains (losses):			
Other commodity derivatives	$ 10,629	$ 10,950	$ 32,477
Interest rate swaps	(2,148)	(1,140)	(3,285)
	$ 8,481	$ 9,810	$ 29,192

6. Fair Value Measurements

We adopted ASC Topic 820 for financial assets and financial liabilities as of January 1, 2008 and for non-financial assets and liabilities as of January 1, 2009. ASC Topic 820 does not expand the use of fair value measurements, but rather, provides a framework for consistent measurement of fair value for those assets and liabilities already measured at fair value under other accounting pronouncements. Certain specific fair value measurements, such as those related to share-based compensation, are not included in the scope of ASC Topic 820. Primarily, ASC Topic 820 is applicable to assets and liabilities related to financial instruments, to some long-term investments and liabilities, to initial valuations of assets and liabilities acquired in a business combination, and to long-lived assets written down to fair value when they are impaired. It does not apply to oil and natural gas properties accounted for under the full cost method, which are subject to impairment based on SEC rules. 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.

Financing arrangements. The carrying amounts of our Term Loan, reserve-based credit facility and ENP revolving credit facility approximate fair value because our current borrowing rates do 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 oil, natural gas 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, options and swaptions. We estimate the fair values of the swaps and swaptions based on published forward commodity price curves for the underlying commodities as of the date of the estimate. We estimate the option value of the contract floors and ceilings using an option pricing model which takes into account market volatility, market prices and contract parameters. The discount rate used in the discounted cash flow projections is based on published LIBOR rates, Eurodollar futures rates and interest swap rates. In order to estimate the fair value of our interest rate swaps, we use a yield curve based on money market rates and interest rate swaps, extrapolate a forecast of future interest rates, estimate each future cash flow, derive discount factors to value the fixed and floating rate cash flows of each swap, and then discount to present value all known (fixed) and forecasted (floating) swap cash flows. Curve building and discounting techniques used to establish the theoretical market value of interest bearing securities are based on readily available money market rates and interest rate swap market data. To extrapolate future cash flows, discount factors incorporating our counterparties' and our credit standing are used to discount future cash flows. We have classified the fair values of all of our derivative contracts as Level 2.

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

	December 31, 2010			
	Fair Value Measurements Using			Assets/ Liabilities at Fair value
	Level 1	Level 2	Level 3	
	(in thousands)			
Assets:				
Commodity price derivative contracts	$ •	$ 29,601	$ •	$ 29,601
Interest rate derivative contracts	•	643	•	643
Total derivative instruments	$ •	$ 30,244	$ •	$ 30,244
Liabilities:				
Commodity price derivative contracts	$ •	$ (44,173)	$ •	$ (44,173)
Interest rate derivative contracts	•	(4,662)	•	(4,662)
Total derivative instruments	$ •	$ (48,835)	$ •	$ (48,835)

	December 31, 2009			
	Fair Value Measurements Using			Assets/ Liabilities at Fair value
	Level 1	Level 2	Level 3	
	(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)

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, 2010, in connection with natural gas and oil properties acquired in the Parker Creek and Encore acquisitions as well as new wells drilled during the year, we incurred and recorded asset retirement obligations totaling $25.7 million at fair value. 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 2.3% and 4.8%; and (4) the average inflation factor (2.3%). The adoption of ASC Topic 820 on January 1, 2009, as it relates to nonfinancial assets and nonfinancial liabilities, did not have a material impact on our financial position or results of operations.

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:

	2010	2009
	(in thousands)	
Asset retirement obligation at January 1,	$ 4,420	$ 2,134
Liabilities added during the current period	25,663	2,504
Accretion expense	132	123
Revisions of estimate	(13)	(341)
Total asset retirement obligation at December 31,	30,202	4,420
Less: current obligations	(768)	•
Long-term asset retirement obligation at December 31,	$ 29,434	$ 4,420

Accretion expense for the years ended December 31, 2010, 2009 and 2008 was $131,909, $122,519 and $61,683, respectively.

8. Related Party Transactions

In Appalachia, we rely on Vinland to execute our drilling program, operate our wells and gather our natural gas. We reimburse Vinland $60 per well per month (in addition to normal third party operating costs) for operating our current natural gas and oil properties in Appalachia under a Management Services Agreement ("MSA") which costs are reflected in our lease operating expenses. Pursuant to an amendment to the MSA, we reimbursed Vinland $95 per well per month for the period from March 1, 2009 through December 31, 2009. Under a Gathering and Compression Agreement ("GCA"), Vinland receives a $0.25 per Mcf transportation fee on existing wells drilled at December 31, 2006 and $0.55 per Mcf transportation fee on any new wells drilled after December 31, 2006 within the area of mutual interest or "AMI." The GCA was amended for the period beginning March 1, 2009 through December 31, 2009, to provide for a temporary fee based upon the actual costs incurred by Vinland to provide gathering and transportation services plus a $0.05 per mcf margin. The amendments to the MSA and the GCA expired on December 31, 2009 and all the terms of the agreements reverted back to the original agreements. In June 2010, we began discussions with Vinland regarding an amendment to the GCA to go into effect beginning on July 1, 2010. The amended agreement would provide gathering and compression services based upon actual costs plus a margin of $.055 per mcf. We and Vinland agreed in principle to this change effective July 1, 2010 and we have jointly operated on this basis since then, however, no formal agreement between us and Vinland has been signed. We are currently negotiating other agreements with Vinland concerning our joint operations and our intent is to have all our operations governed under a single set of agreements, including this amendment to the GCA. In the event no agreement is reached between us and Vinland, all the terms of the agreements will revert back to the original agreements effective July 1, 2010. Under the GCA, the transportation fee that we pay to Vinland only encompasses transporting the natural gas to third party pipelines at which point additional transportation fees to natural gas markets would apply. These transportation fees are outlined in the GCA and are reflected in our lease operating expenses. For the years ended December 31, 2010, 2009 and 2008, costs incurred under the MSA were $1.9 million, $1.6 million and $0.6 million, respectively and costs incurred under the GCA were $1.4 million, $1.2 million and $1.0 million, respectively. A payable of $0.6 million and $1.4 million, respectively, is included in our December 31, 2010 and 2009 consolidated balance sheets in connection with these agreements and direct expenses incurred by Vinland related to the drilling of new wells and operations of all of our existing wells in Appalachia.

In September 2008, the Company acquired certain oil and natural gas 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, 2010, beneficially owned 8.5% 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 10%, and received well, strata, and leasehold interests with an approximately equal value; therefore no gain or loss was recognized.

In connection with closing of the Encore Acquisition, VNG entered into a Second Amended and Restated Administrative Services Agreement, dated December 31, 2010, with ENP, ENP GP, Encore Operating, L.P. ("Encore Operating"), OLLC and Denbury (the "Services Agreement"). The Services Agreement was amended solely to add VNG as a party and provide for VNG to assume the rights and obligations of Encore Operating and Denbury under the previous administrative services agreement going forward.

Pursuant to the Services Agreement, VNG will provide certain general and administrative services to ENP, ENP GP and the OLLC (collectively, the "ENP Group") in exchange for a quarterly fee of $2.06 per barrel of oil equivalent of the ENP Group's total net oil and gas production for the most recently-completed quarter, which fee is paid by ENP (the "Administrative Fee"). The Administrative Fee is subject to certain index-related adjustments on an annual basis. ENP also is obligated to reimburse VNG for all third-party expenses it incurs on behalf of the ENP Group. These terms are identical to the terms under which Denbury and Encore Operating provided administrative services to the ENP Group prior to the second amendment and restatement of the Services Agreement. VNG will receive the fees and reimbursements for services performed in 2011. The administrative fee will increase in the following circumstances:

- beginning on the first day of April in each year by an amount equal to the product of the then-current administrative fee multiplied by the COPAS Wage Index Adjustment for that year;
- if ENP acquires additional assets, VNG may propose an increase in its administrative fee that covers the provision of services for such additional assets; however, such proposal must be approved by the board of directors of the ENP GP upon the recommendation of its conflicts committee; and
- otherwise as agreed upon by VNG and the ENP GP, with the approval of the conflicts committee of the board of directors of the ENP GP.

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. Discovery is ongoing between the parties.

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; however, on August 5, 2010, the case was bifurcated and the claims against the Company shall only be heard in the event liability is proven against the initial defendants. 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 0.5% of our estimated proved reserves as of December 31, 2010. 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, 2010, 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 had a dilutive effect for the year ended December 31, 2010; therefore, they have been included in the computation of diluted earnings per unit. However, these options did not have a dilutive effect for the years ended December 31, 2009 and 2008; 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 for the years ended December 31, 2010, 2009 and 2008; therefore, they have also been excluded in the computation of diluted earnings per unit.

In accordance with ASC Topic 260, dual presentation of basic and diluted earnings per unit has been presented in the consolidated statements of operations for the years ended December 31, 2010, 2009 and 2008 including each class of units issued and outstanding at that date: common units and Class B units. Net income (loss) per unit is allocated to the common units and the Class B units on an equal basis.

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 vested after three years. The remaining 40,000 restricted Class B units were not granted and are not expected to be granted in the future.

In October 2007, 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 was equal to the appreciation in value of the units from the date of the grant until the determination date (December 31, 2009), plus cash distributions paid on the units, less an 8% hurdle rate. At 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. In January and March 2010, four board members were each granted 3,764 common units, one officer was granted 6,500 common units and one board member was granted 2,663 common units each of which will vest after one year.

In February 2010, the Company and VNRH entered into second amended and restated Executive Employment Agreements (the “Amended Agreements”) with two executives. The Amended Agreements were effective January 1, 2010 and will continue until January 1, 2013, with subsequent one year renewals in the event that neither we, VNRH nor the executives have given notice to the other parties that the agreements should not be extended. Also in June 2010, the Company and VNRH entered into a second amended and restated Executive Employment Agreement (the “Amended Agreement”) with one executive. The Amended Agreement was effective May 15, 2010 and will continue until May 15, 2013, with subsequent one year renewals in the event that neither we, VNRH nor the executive have given notice to the other parties that the agreements should not be extended. All three Amended Agreements provide for an annual base salary and include an annual bonus structure for the executives. The annual bonus will be calculated based upon two company performance elements, absolute target distribution growth and relative unit performance to peer group, as well as a third discretionary element to be determined by our board of directors for the Amended Agreements entered into in February 2010 and by the Chief Executive officer for the Amended Agreement entered into in June 2010. Each of the three components will be weighted equally in calculating the respective executive officer’s annual bonus. The annual bonus does not require a minimum payout, although the maximum payout may not exceed two times the respective executive’s annual base salary. At December 31, 2010, an accrued liability and compensation expense of $1.5 million was recognized in the selling, general and administrative expenses line item in the consolidated statement of operations.

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

In addition, the Amended Agreements entered into in February 2010 provide for each executive to receive an annual grant of 15,000 phantom units granted pursuant to the LTIP and the Amended Agreement entered into in June 2010 provides for the executive to receive an annual grant of 12,500 phantom units granted pursuant to the LTIP. The phantom units are also subject to a three year vesting period, although the vesting is not pro-rata, but a one-time event which shall occur on the three year anniversary of the date of grant so long as the executive remains continuously employed with the Company during such time. The phantom units are accompanied by dividend equivalent rights, which entitle the executives to receive the value of any distributions made by the Company on its units generally with respect to the number of phantom units that the 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. For each executive under the February 2010 amended agreements, the amount to be paid in connection with these phantom units, can be paid in cash or in units at the election of the officers and will be equal to the appreciation in value of the units from the date of the grant until the determination date (December 31, 2013). For the executive under the June 2010 amended agreement, the amount to be paid in connection with these phantom units, will be settled through the delivery of a number of units equal to the number of phantom units granted. As of December 31, 2010, an accrued liability associated with the phantom units of $0.2 million has been recorded and non-cash unit-based compensation expense of $0.2 million has been recognized for year ended December 31, 2010, in the selling, general and administrative expense line item in the consolidated statement of operations.

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

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

At December 31, 2010, there was approximately $0.8 million of unrecognized compensation cost related to non-vested restricted units. The cost is expected to be recognized over an average period of approximately 1.4 years. Our consolidated statements of operations reflects non-cash compensation of $1.0 million, $2.5 million and $3.6 million in the selling, general and administrative expenses line item for the years ended December 31, 2010, 2009 and 2008, respectively.

Unit-based awards were made to VNR employees in January and February 2011. See Note 13. *Subsequent Events* for further discussion.

In September 2007, the board of directors of ENP GP adopted the Encore Energy Partners GP LLC Long-Term Incentive Plan (the " ENP LTIP"), which provides for the granting of options, restricted units, phantom units, unit appreciation rights, distribution equivalent rights, other unit-based awards, and unit awards. All employees, consultants, and directors of ENP GP and its affiliates who perform services for or on behalf of ENP and its subsidiaries are eligible to be granted awards under the ENP LTIP. The ENP LTIP is administered by the board of directors of ENP GP or a committee thereof, referred to as the plan administrator. To satisfy common unit awards under the ENP LTIP, ENP may acquire common units in the open market, use common units owned by ENP GP, or use common units acquired by ENP GP from ENP or from any other person.

The total number of common units reserved for issuance pursuant to the ENP LTIP is 1,150,000. As of December 31, 2010, there were 1,075,000 common units available for issuance under the ENP LTIP.

12. Shelf Registration Statements

In November 2008, ENP's shelf registration statement on Form S-3 was declared effective by the SEC. Under the shelf registration statement, ENP may offer common units, senior debt, or subordinated debt in one or more offerings with a total initial offering price of up to $1 billion. In May 2009, ENP issued 2,760,000 common units under its shelf registration statement at a price to the public of $15.60 per common unit. In July 2009, ENP issued 9,430,000 common units under its shelf registration statement at a price to the public of $14.30 per common unit. As a result of these offerings, as of December 31, 2010, ENP has approximately $822.1 million remaining available under its 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 2009 shelf registration statement is determined at the time of the offerings. The shelf registration statement does not provide assurance that we will or could sell any such securities. Our ability to utilize the shelf registration statement for the purpose of issuing, from time to time, any combination of debt securities or common units will depend upon, among other things, market conditions and the existence of investors who wish to purchase our securities at prices acceptable to us.

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

In May 2010, we completed an offering of 3.3 million of our common units. The units were offered to the public at a price of $23.00 per unit. We received proceeds of approximately $71.5 million from the offering, after deducting underwriting discounts of $3.2 million and offering costs of $0.1 million.

In July 2010, we filed a registration statement with the SEC which registered offerings of up to $800.0 million of any combination of debt securities, common units and guarantees of debt securities by our subsidiaries. Net proceeds, terms and pricing of the offering of securities issued under the 2010 shelf registration statement will be determined at the time of the offerings. The shelf registration statement does not provide assurance that we will or could sell any such securities. Our ability to utilize the shelf registration statement for the purpose of issuing, from time to time, any combination of debt securities or common units will depend upon, among other things, market conditions and the existence of investors who wish to purchase our securities at prices acceptable to us.

In August 2010, we entered into an equity distribution agreement relating to our common units representing limited liability company interests having an aggregate offering price of up to $60.0 million. In accordance with the terms of the equity distribution agreement we may offer and sell up to the maximum dollar amount of our units from time to time through our sales agent. Sales of the units, if any, may be made by means of ordinary brokers' transactions through the facilities of the New York Stock Exchange, or NYSE, at market prices. Our sales agent will receive from us a commission of 1.25% based on the gross sales price per unit for any units sold through it as agent under the equity distribution agreement. During September through December 2010, we received net proceeds of approximately $6.3 million from the sales of 240,111 common units, after commissions.

In October 2010, we completed an offering of 4.8 million of our common units. The units were offered to the public at a price of $25.40 per unit. We received net proceeds of approximately $115.8 million from the offering, after deducting underwriting discounts of $5.1 million and offering costs of $0.3 million. We paid $3.7 million of the proceeds of this offering to redeem 150,000 common units from our founding unitholder. The net proceeds of $112.1 million were used to pay down outstanding borrowings under our reserve-based credit facility.

As a result of these offerings, as of December 31, 2010, we have approximately $62.6 million and $678.8 million remaining available under our 2009 and 2010 shelf registration statements, respectively.

13. Subsequent Events

In January and February 2011, VNR employees were granted a total of 102,906 common units which vest equally over a four year period, but have distribution equivalent rights that provide the employees with a payment equal to the distribution on unvested units.

In January 2011, ENP issued 140,007 restricted ENP units under the ENP LTIP to Vanguard field employees performing services on ENP's properties (grant was equal to one-year salary for each employee who received a grant). These awards vest equally over a four-year period, but have distribution equivalent rights that provide the employees with a payment equal to the distribution on unvested units.

On January 27, 2011, the board of directors declared a cash distribution attributable to the fourth quarter of 2010 of $0.56 per unit that was paid on February 14, 2011 to unitholders of record as of the close of business on February 7, 2011.

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)				
2010					
Oil, natural gas and natural gas liquids sales	$ 20,070	$ 19,446	$ 22,684	$ 23,157	$ 85,357
Loss on commodity cash flow hedges	(1,042)	(517)	(568)	(705)	(2,832)
Realized gain on other commodity derivative contracts	5,214	6,547	6,513	6,500	24,774
Unrealized gain (loss) on other commodity derivative contracts	10,810	(90)	(9,388)	(15,477)	(14,145)
Total revenues	$ 35,052	$ 25,386	$ 19,241	$ 13,475	$ 93,154
Total costs and expenses	$ 11,293	$ 13,361	$ 13,874	$ 19,148	$ 57,676
Loss on acquisition of oil and natural gas properties	$ •	$ (5,680)	$ •	$ •	$ (5,680)
Net income (loss)	$ 21,703	$ 3,905	$ 1,912	$ (5,635)	$ 21,885
Net income (loss) per unit:					
Common & Class B units – basic & diluted	$ 1.15	$ 0.19	$ 0.09	$ (0.21)	$ 1.00
2009					
Oil, natural gas and natural gas liquids 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 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 oil and natural gas 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 oil and natural gas 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 & diluted	$ (3.98)	$ (0.54)	$ 0.05	$ (2.31)	$ (6.74)

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

Supplemental Oil and Natural Gas Information (Unaudited)

We are a publicly-traded limited liability company focused on the acquisition and development of mature, long-lived oil and natural gas properties in the United States.

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

	2010	2009
	(in thousands)	
Aggregate capitalized costs relating to oil, natural gas and natural gas liquids producing activities	$ 1,312,107	$ 399,212
Aggregate accumulated depletion, amortization and accretion	(248,704)	(226,687)
Net capitalized costs	$ 1,063,403	$ 172,525
ASC Topic 410-20 asset retirement obligations (included above)	$ 30,202	$ 4,420

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

	2010	2009	2008
		(in thousands)	
Property acquisition costs	$ 896,676	$ 106,776	$ $128,324
Development costs	15,662	5,825	19,097
Total cost incurred	$ 912,338	$ 112,601	$ 147,421

No internal costs were capitalized in 2010, 2009 or 2008. Additionally, capitalized interest of $58,960 for the year ended December 31, 2008 is included in the table above. There was no capitalized interest in 2010 or 2009.

Net quantities of proved developed and undeveloped reserves of oil and natural gas and changes in these reserves at December 31, 2010, 2009 and 2008 are presented below. Information in these tables is based on reserve reports prepared by our independent petroleum engineers, Netherland, Sewell & Associates, Inc. for 2009 and 2008 and DeGolyer and MacNaughton in 2010 and 2009. Additionally, information in these tables includes the non-controlling interest in the ENP reserves of approximately 53.3% at December 31, 2010.

	Gas (in Mcf)	Oil (in Bbls)	NGL (in Bbls)
Net proved reserves			
January 1, 2008	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
Revisions of previous estimates	(7,607)	332,850	956,685
Extensions, discoveries and other	76,376	17,515	•
Purchases of reserves in place	75,715,424	32,040,203	1,210,687
Production	(4,990,017)	(682,447)	(209,531)
December 31, 2010	153,942,674	38,120,869	5,507,991
Proved developed reserves			
December 31, 2008	58,315,899	3,766,394	•
December 31, 2009	54,129,281	4,765,599	2,360,526
December 31, 2010	119,312,949	31,853,857	3,933,643
Proved undeveloped reserves			
December 31, 2008	22,921,198	780,965	•
December 31, 2009	29,019,217	1,647,149	1,189,624
December 31, 2010	34,629,725	6,267,012	1,574,348

Revisions of previous estimates of reserves are a result of changes in oil and natural gas prices, production costs, well performance and the reservoir engineer's methodology. The initial application of the new rules related to modernizing reserve calculations and disclosure requirements resulted in a downward adjustment of 1.8 MMBOE 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 2.4 MMBOE 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 0.6 MMBOE 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 1.8 MMBOE to our total proved reserves due to the new SEC rules was more than offset by a 12.5 MMBOE increase in our reserves due to acquisitions completed during the year ended December 31, 2009. Our reserves increased by 45.9 MMBOE during the year ended December 31, 2010 due primarily to the ENP and Parker Creek acquisitions completed during 2010.

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 oil and natural gas 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 oil and natural gas 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 oil and natural gas 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, 2010.

Our proved undeveloped reserves at December 31, 2010, as estimated by our independent petroleum engineers, were 13.6 MMBOE, consisting of 6.3 million barrels of oil, 34.6 MMcf of natural gas and 1.6 million barrels of natural gas liquids. Proved undeveloped reserves that we acquired in connection with the Encore Acquisition are subject to a 53.3% non-controlling interest in ENP. In 2010, we developed approximately 1.5% of our total proved undeveloped reserves booked as of December 31, 2009 through the drilling of two gross (1.5 net) well at an aggregate capital cost of approximately $7.8 million. None of our proved undeveloped reserves at December 31, 2010 have remained undeveloped for more than five years since the date of initial booking as proved undeveloped reserves. At December 31, 2010, there are 6 locations with 0.3 MMBOE 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.

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

	2010	2009	2008
		(in thousands)	
Production revenues (1)	$ 107,299	$ 73,648	$ 62,543
Production costs (2)	(24,858)	(16,722)	(15,800)
Depreciation, depletion and amortization	(22,019)	(14,440)	(14,812)
Impairment of oil and natural gas properties	•	(110,154)	(58,887)
Results of operations from producing activities	$ 60,422	$ (67,668)	$ (26,956)

(1) Production revenues include gains and losses on commodity cash flow hedges in 2010, 2009 and 2008 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 oil and natural gas reserves at December 31 is as follows:

	2010 (1)	2009	2008
		(in thousands)	
Future cash inflows	$ 3,670,000	$ 846,196	$ 739,560
Future production costs	(1,266,940)	(362,386)	(258,948)
Future development costs	(156,714)	(95,297)	(50,268)
Future net cash flows	2,246,346	388,513	430,344
10% annual discount for estimated timing of cash flows	(1,127,898)	(209,840)	(240,271)
Standardized measure of discounted future net cash flows	$ 1,118,448	$ 178,673	$ 190,073

(1) The standardized measure includes approximately $596.1 million attributable to the non-controlling interest of ENP.

For the December 31, 2010 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 $4.38 per MMBtu for natural gas and $79.40 per barrel of crude oil adjusted for quality, transportation fees and a regional price differential for Vanguard and the 12-month average price of $4.45 per MMBtu for natural gas and $79.43 per barrel of crude oil adjusted for quality, transportation fees and a regional price differential for ENP. 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)		
	2010	2009	2008
		(in thousands)	
Sales and transfers, net of production costs	$ (60,046)	$ (29,313)	$ (53,050)
Net changes in prices and production costs	91,799	(21,697)	(20,385)
Extensions discoveries and improved recovery, less related costs	891	1,673	13,036
Changes in estimated future development costs	(9,476)	2,557	(12,056)
Previously estimated development costs incurred during the period	15,662	5,825	19,956
Revision of previous quantity estimates	16,728	(64,155)	(10,149)
Accretion of discount	17,867	19,007	15,100
Purchases of reserves in place (2)	856,299	80,776	82,454
Change in production rates, timing and other	10,051	(6,073)	4,170
Net change	$ 939,775	$ (11,400)	$ 39,076

(1) This disclosure reflects changes in the standardized measure calculation excluding the effects of hedging activities.
(2) The portion associated with the ENP acquisition includes the non-controlling interest in the ENP reserves of approximately 53.3% at December 31, 2010.

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 designed to ensure 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, 2010.

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2010, is set forth in Item 9A(b) below.

BDO USA, 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, 2010, 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, 2010. 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, 2010. Management excluded from its evaluation the internal control over financial reporting of ENP which was acquired on December 31, 2010. The total assets and liabilities of ENP were $653.6 million and $304.6 million, respectively, as of December 31, 2010. The effectiveness of our internal control over financial reporting as of December 31, 2010 has been audited by BDO USA, 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 2010 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting, except for the changes in internal control over financial reporting associated with integrating the Encore Acquisition that was completed on December 31, 2010.

(d) Attestation Report

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

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

We have audited Vanguard Natural Resources, LLC's internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Vanguard Natural Resources, LLC's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying "Item 9A, Management's Report on Internal Control Over Financial Reporting". Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

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

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

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

As indicated in the accompanying "Item 9A, Management's Annual Report on Internal Control Over Financial Reporting", management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include internal controls of Encore Energy Partners LP, which was acquired on December 31, 2010, and which is included in the consolidated balance sheet of Vanguard Natural Resources, LLC as of December 31, 2010. The financial statements of Encore Energy Partners LP reflect total assets and liabilities of $653.6 million and $304.6 million, respectively, as of December 31, 2010. Management did not assess the effectiveness of internal control over financial reporting of Encore Energy Partners LP because of the timing of the acquisition, which was completed on December 31, 2010. Our audit of internal control over financial reporting of Vanguard Natural Resources, LLC also did not include an evaluation of the internal control over financial reporting of Encore Energy Partners LP.

In our opinion, Vanguard Natural Resources, LLC maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, 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, 2010 and 2009, and the related consolidated statements of operations, comprehensive income, members' equity, and cash flows for each of the three years in the period ended December 31, 2010 and our report dated March 8, 2011 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP

Houston, Texas
March 8, 2011

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, 2010.

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, 2010.

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, 2010.

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, 2010.

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, 2010.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

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

Financial statements

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

(b) Exhibits

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

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, 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)
10.7	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 (File No. 001-33756)
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 (File No. 001-33756)
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 (File No. 001-33756)
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 (File No. 001-33756)
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 (File No. 001-33756)
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 (File No. 001-33756)
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 (File No. 001-33756)
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 (File No. 001-33756)
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 (File No. 001-33756)
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 Richard A. Robert, 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)
10.48	Asset Purchase Agreement, dated April 30, 2010, by and between Alpine Gas Investors, LP and Vanguard Permian, LLC	Form 8-K, filed May 5, 2010 (File No. 001-33756)
10.49	Second Amendment to Second Amended and Restated Credit Agreement, dated June 1, 2010, among Vanguard Natural Gas, LLC, Citibank, N.A. , Existing Lenders (as defined therein), and Credit Agricole Corporate and Investment Bank	Form 8-K, filed June 4, 2010 (File No. 001-33756)
10.50+	Employment Agreement, dated June 18, 2010, by and between Britt Pence, VNR Holdings, LLC and Vanguard Natural Resources, LLC	Previously filed with our Quarterly report on Form 10-Q on August 4, 2010 (File No. 001-33756)
10.51+	Restricted Unit Award Agreement, by and between Vanguard Natural Resources, LLC and Britt Pence	Previously filed with our Quarterly report on Form 10-Q on August 4, 2010 (File No. 001-33756)
10.52+	Phantom Unit Award Agreement, by and between Vanguard Natural Resources, LLC, VNR Holdings, LLC and Britt Pence	Previously filed with our Quarterly report on Form 10-Q on August 4, 2010 (File No. 001-33756)
10.53	Purchase and Sale Agreement, dated November 16, 2010 among Vanguard Natural Resources, LLC, Vanguard Natural Gas, LLC, Denbury Resources Inc., Encore Partners GP Holdings LLC, Encore Partners LP Holdings LLC and Encore Operating, L.P.	Form 8-K, filed November 17, 2010 (File No. 001-33756)
10.54	Term Loan, dated November 16, 2010 by and between Vanguard Natural Gas, LLC and BNP Paribas, as administrative agent, and the lenders party thereto	Form 8-K, filed November 17, 2010 (File No. 001-33756)
10.55	Third Amendment to Second Amended and Restated Credit Agreement, dated November 16, 2010 by and between Vanguard Natural Gas, LLC, Citibank, N.A., as administrative agent and the lenders party hereto	Form 8-K, filed November 17, 2010 (File No. 001-33756)
10.56	Registration Rights Agreement, dated December 31, 2010, by and between Vanguard Natural Resources, LLC and Encore Operating, L.P.	Form 8-K, filed January 3, 2011 (File No. 001-33756)
10.57	Second Amended and Restated Administrative Services Agreement, dated December 31, 2010, by and among Vanguard Natural Gas, LLC, Denbury Resources Inc., Encore Energy Partners GP LLC, Encore Energy Partners LP, Encore Operating, L.P. and Encore Energy Partners Operating LLC	Form 8-K, filed January 3, 2011 (File No. 001-33756)
10.58	First Amendment, dated December 31, 2010, to Term Loan Agreement among Vanguard Natural Gas, LLC, BNP Paribas, as Administrative Agent, and the Lenders party thereto	Form 8-K, filed January 3, 2011 (File No. 001-33756)
10.59	Fourth Amendment, dated December 31, 2010, to Second Amended and Restated Credit Agreement among Vanguard Natural Gas, LLC, the Guarantors named therein, Citibank, N.A., as Administrative Agent and L/C Issuer, and the Lenders party thereto	Form 8-K, filed January 3, 2011 (File No. 001-33756)
16.1	Letter Regarding Change in Certifying Accountant	Form 8-K, filed on September 2, 2008 (File No. 001-33756)
21.1	List of subsidiaries of Vanguard Natural Resources, LLC	Filed herewith
23.1	Consent of BDO USA, LLP, Independent Registered Public Accounting Firm	Filed herewith
23.2	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 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 8th day of March, 2011.

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 8, 2011	/s/ Scott W. Smith Scott W. Smith President, Chief Executive Officer and Director (Principal Executive Officer)
March 8, 2011	/s/ Richard A. Robert Richard A. Robert Executive Vice President and Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)
March 8, 2011	/s/ W. Richard Anderson W. Richard Anderson Director
March 8, 2011	/s/ Bruce W. McCullough Bruce W. McCullough Director
March 8, 2011	/s/ John R. McGoldrick John R. McGoldrick Director
March 8, 2011	/s/ Loren Singletary Loren Singletary Director
March 8, 2011	/s/ Lasse Wagene Lasse Wagene Director

EXHIBIT 21.1

Vanguard Natural Resources, LLC
SUBSIDIARIES OF THE REGISTRANT
as of December 31, 2010

Entity Name	Place of Incorporation	Owner	Percentage Ownership
Trust Energy Company, LLC	Kentucky	Vanguard Natural Gas, LLC	100%
Ariana Energy, LLC	Tennessee	Vanguard Natural Gas, LLC	100%
Vanguard Natural Gas, LLC	Kentucky	Vanguard Natural Resources, LLC	100%
VNR Holdings, LLC	Delaware	Vanguard Natural Gas, LLC	100%
Vanguard Permian, LLC	Delaware	Vanguard Natural Gas, LLC	100%
VNR Finance Corp.	Delaware	Vanguard Natural Resources, LLC	100%
Encore Energy Partners GP LLC	Delaware	Vanguard Natural Resources, LLC	100%
Encore Energy Partners LP	Delaware	Vanguard Natural Gas, LLC	45.6% (1)
Encore Energy Partners LP	Delaware	Encore Energy Partners GP LLC	1.1% (2)
Encore Energy Partners Operating LLC	Delaware	Encore Energy Partners LP	100%
Encore Energy Partners Finance Corporation	Delaware	Encore Energy Partners LP	100%
Encore Clear Fork Pipeline LLC	Delaware	Encore Energy Partners LP	100%

(1) Limited partner interest.
(2) General partner interest.

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

Vanguard Natural Resources, LLC
Houston, Texas

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-159911 and 333-168177) and Form S-8 (No. 333-152448) of Vanguard Natural Resources, LLC of our reports dated March 8, 2011, relating to the consolidated financial statements and the effectiveness of Vanguard Natural Resources, LLC's internal control over financial reporting, which appear in this Form 10-K for the year ended December 31, 2010.

BDO USA, LLP
Houston, Texas

March 8, 2011

Exhibit 23.2

Consent of Independent Petroleum Engineers and Geologists

DEGOLYER AND MACNAUGHTON
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

March 7, 2011

Vanguard Natural Resources LLC.
5847 San Felipe Suite 3000
Houston, Texas 777057

Ladies and Gentlemen:

We hereby consent to the use of the name DeGolyer and MacNaughton, to references to DeGolyer and MacNaughton, to the inclusion of our letter report dated January 18, 2011, related to the proved oil, NGL, and natural gas reserves and future net revenues of Vanguard Natural Resources, LLC for the year ending December 31, 2010, and to the inclusion of information from our "Appraisal Report as of December 31, 2010 on Certain Properties owned by Vanguard Natural Resources LLC" and our "Appraisal Report as of December 31, 2010 on Certain Properties owned by Encore Energy Partners LLC" in the Annual Report on Form 10-K of Vanguard Natural Resources LLC for the year ended December 31, 2010. We further consent to the inclusion by reference of the Vanguard Natural Resources LLC. Annual Report on Form 10-K for the year ended December 31, 2010 in the Registration Statements on Form S-3 (No. 333-159911 and Form S-8 (No. 333-152448).

Very truly yours,

/s/ DeGolyer and MacNaughton
DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716

EXHIBIT 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER PURSUANT TO RULE 13A- 14(A) AND RULE 15D-14(A) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Scott W. Smith, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: March 8, 2011

/s/ Scott W. Smith
Scott W. Smith

President and Chief Executive Officer
(Principal Executive Officer)
Vanguard Natural Resources, LLC

EXHIBIT 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER PURSUANT TO RULE 13A- 14(A) AND RULE 15D-14(A) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Richard A. Robert, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: March 8, 2011

/s/ Richard A. Robert
Richard A. Robert

Executive Vice President and
Chief Financial Officer
(Principal Financial Officer and Principal Accounting Officer)
Vanguard Natural Resources, LLC

EXHIBIT 32.1

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

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

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

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

/s/ Scott W. Smith
Scott W. Smith

President and Chief Executive Officer
(Principal Executive Officer)

March 8, 2011

EXHIBIT 32.2

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

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

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

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

/s/ Richard A. Robert
Richard A. Robert

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

March 8, 2011

DeGolyer and MacNaughton

5001 Spring Valley Road
Suite 800 East
Dallas, Texas75244

Exhibit 99.1

January 18, 2011

Vanguard Natural Resources
5847 San Felipe, Suite 3000
Houston, Texas 77057

Gentlemen:

Pursuant to your request, we have prepared estimates of the extent and value of the net proved crude oil, condensate, natural gas liquids (NGL), and natural gas reserves, as of December 31, 2010, of certain properties owned by Vanguard Natural Resources (Vanguard). Vanguard has represented that these properties account for 100 percent on a net equivalent barrel basis of Vanguard's net proved reserves as of December 31, 2010. The net proved reserves estimates prepared by us have been prepared in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the Securities and Exchange Commission (SEC) of the United States.

Reserves included herein are expressed as net reserves. Gross reserves are defined as the total estimated petroleum to be produced from these properties after December 31, 2010. Net reserves are defined as that portion of the gross reserves attributable to the interests owned by Vanguard after deducting all interests owned by others. Gas quantities estimated herein are expressed as sales gas. Sales gas is defined as that portion of the total gas to be delivered into a gas pipeline for sale after separation, processing, fuel use, and flare. Gas reserves are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at a pressure base of 14.65 pounds per square inch absolute (psia). Condensate reserves estimated herein are those to be recovered by conventional lease separation.

Values shown herein are expressed in terms of future gross revenue, future net revenue, and present worth. Future gross revenue is that revenue which will accrue to the appraised interests from the production and sale of the estimated netreserves. Future net revenue is calculated by deducting estimated production taxes, ad valorem taxes, operating expenses, and capital costs from the future gross revenue. Operating expenses include field operating expenses, transportation expenses, compression charges, and an allocation of overhead that directly relates to production activities. Future income tax expenses were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at a specified arbitrary discount rate compounded monthly over the expected period of realization.

Estimates of oil, condensate, NGL, and natural gas should be regarded only as estimates that may change as further production history and additional information become available. Not only are such reserves estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Data used in this evaluation were obtained from reviews with Vanguard personnel, Vanguard files, from records on file with the appropriate regulatory agencies, and from public sources. Additionally, this information includes data supplied by Petroleum Information/Dwights LLC; Copyright 2010 Petroleum Information/Dwights LLC. In the preparation of this report we have relied, without independent verification, upon such information furnished by Vanguard with respect to property interests, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination of the properties was not considered necessary for the purposes of this report.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principals and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007)." The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

When applicable, the volumetric method was used to estimate the original oil in place (OOIP) and the original gas in place (OGIP). Structure and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation. When adequate data were available and when circumstances justified, material balance and other engineering methods were used to estimate OOIP or OGIP.

Estimates of ultimate recovery were obtained after applying recovery factors to OOIP or OGIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and the production histories. When applicable, material balance and other engineering methods were used to estimate recovery factors. An analysis of reservoir performance, including production rate, reservoir pressure, and gas-oil ratio behavior, was used in the estimation of reserves.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production or to the limit of the production licenses as appropriate.

Definition of Reserves

Petroleum reserves estimated by us included in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used by us in this report are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

Proved oil and gas reserves – Proved oil and gas reserves are those quantities of oil and 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•prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:
(A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Developed oil and gas reserves – Developed oil and gas reserves are reserves of any category that can be expected to be recovered:
(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment andinfrastructure operational atthe time of the reserves estimate if the extraction is by means not involving a well.

Undeveloped oil and gas reserves – Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in [section 210.4–10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

Primary Economic Assumptions

The following economic assumptions were used for estimating existing and future prices and costs:

Oil and Condensate Prices

Vanguard has represented that the oil and condensate prices were based on a 12-month average price (reference price), calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. Vanguard supplied differentials by field to a West Texas Intermediate reference price of $79.40 per barrel and the prices were held constant thereafter. The volume-weighted average oil price was $72.04 per barrel.

NGL Prices

Vanguard has represented that the NGL prices were based on a 12-month average price (reference price), calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. Vanguard supplied differentials by field to a West Texas Intermediate reference price of $79.40 per barrel and the prices were held constant thereafter. The volume-weighted average NGL price was $45.35 per barrel.

Natural Gas Prices

Vanguard has represented that the natural gas prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. The gas prices were calculated for each property using differentials to the reference price of $4.38 per Mcf furnished by Vanguard and held constant thereafter. The volume-weighted average price was $5.324 per Mcf.

Operating Expenses and Capital Costs

Operating expenses and capital costs, based on information provided by Vanguard, were used in estimating future costs required to operate the properties. In certain cases, future costs, either higher or lower than existing costs, may have been used because of anticipated changes in operating conditions. These costs were not escalated for inflation.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its oil and gas reserves, we are not aware of any such governmental actions which would restrict the recovery of the December 31, 2010, estimated oil and gas volumes. The reserves estimated in this report can be produced under current regulatory guidelines.

Our estimates of Vanguard's net proved reserves attributable to the reviewed properties are based on the definitions of proved reserves of the SEC and are as follows, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcf), and thousands of barrels of oil equivalent (Mboe):

	Net Proved Reserves as of December 31, 2010			
	Oil and Condensate (Mbbl)	**NGL (Mbbl)**	**Sales Gas (MMcf)**	**Oil Equivalent (Mboe)**
Appalachia				
Proved Developed	343	0	28,929	5,165
Proved Undeveloped	0	0	14,606	2,434
Total Proved Appalachia	**343**	**0**	**43,535**	**7,599**
Mississippi				
Proved Developed	2,207	0	127	2,228
Proved Undeveloped	1,931	0	0	1,931
Total Proved Mississippi	**4,138**	**0**	**127**	**4,159**
Permian				
Proved Developed	4,624	369	3,844	5,634
Proved Undeveloped	1,426	248	1,285	1,888
Total Proved Permian	**6,050**	**617**	**5,129**	**7,522**
South Texas				
Proved Developed	76	2,355	19,414	5,667
Proved Undeveloped	71	1,326	11,211	3,265
Total Proved South Texas	**147**	**3,681**	**30,625**	**8,932**
Total Proved	**10,678**	**4,298**	**79,416**	**28,212**

Note: Gas is converted to oil equivalent using a factor of 6,000 cubic feet of gas per 1barrel of oil equivalent.

The estimated future revenue attributable to Vanguard's interests in the proved reserves, as of December 31, 2010, of the properties appraised is summarized as follows, expressed in thousands of dollars (M$):

	Developed Producing	**Developed Nonproducing**	**Undeveloped**	**Total**
Future Gross Revenue, M$	860,653	64,875	461,460	1,386,988
Production and Ad Valorem Taxes, M$	64,192	4,444	32,017	100,653
Operating Expenses, M $	261,720	2,956	86,471	351,147
Capital Costs, M$	5,291	1,969	97,699	104,959
Future Net Revenue*, M$	529,450	55,506	245,273	830,229
Present Worth at 10 Percent*, M$	286,494	26,153	102,271	414,918

* Future income tax expenses were not taken into account in the preparation of these estimates.

In our opinion, the information relating to estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of oil, condensate, natural gas liquids, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, 932-235-50-9,932-235-50-30, and 932-235-50-31(a), (b), and (e) of the Accounting Standards Update 932-235-50, *Extractive Industries – Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures* (January 2010) of the Financial Accounting Standards Board and Rules 4–10(a) (1)–(32) of Regulation S–X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (8), and 1203(a) of Regulation S–K of the Securities and Exchange Commission;provided, however, future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over 70 years. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Vanguard. Our fees were not contingent on the results of our evaluation. This letter report has been prepared at the request of Vanguard. DeGolyer and MacNaughton has used all assumptions, data, procedures, and methods that it considers necessary and appropriate to prepare this report.

Submitted,

/s/ DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

CERTIFICATE of QUALIFICATION

I, Paul J. Szatkowski, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am a Senior Vice President with DeGolyer and MacNaughton, which company did prepare the letter report addressed to Vanguard dated January 18, 2011, and that I, as Senior Vice President, was responsible for the preparation of this report.

2. That I attended Texas A&M University, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in 1974; that I am a Registered Professional Engineer in the State of Texas;that I am a member of the International Society of Petroleum Engineers and the American Association of Petroleum Geologists; and that I have in excess of 36 years of experience in oil and gas reservoir studies and reserves evaluations.

/s/ Paul J. Szatkowski, P.E.

Paul J. Szatkowski, P.E.
Senior Vice President
DeGolyer and MacNaughton