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

Form 10–K

☑ **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**

Commission File Number
001-33024

EV Energy Partners, L.P.
(Exact name of registrant as specified in its charter)

Delaware	**20–4745690**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1001 Fannin, Suite 800, Houston, Texas	**77002**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: **(713) 651-1144**

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

Common Units Representing Limited Partner Interests	**NASDAQ Stock Market LLC**
(Title of each class)	(Name of each exchange on which registered)

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 o

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 or any amendment to the Form 10–K. ☐

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

Large accelerated filer ☑	Accelerated filer ☐
Non-accelerated filer ☐	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 the common units held by non–affiliates at June 30, 2010 based on the closing price on the NASDAQ Global Market on June 30, 2010 was $795,536,383.

As of February 18, 2011, the registrant had 30,723,650 common units outstanding.

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GLOSSARY OF OIL AND NATURAL GAS TERMS

Bbl. One stock tank barrel or 42 U.S. gallons liquid volume of oil or other liquid hydrocarbons.

Bcf. One billion cubic feet of natural gas.

Bcfe. One billion cubic feet equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

Btu. A British thermal unit is a measurement of the heat generating capacity of natural gas. One Btu is the heat required to raise the temperature of a one–pound mass of pure liquid water one degree Fahrenheit at the temperature at which water has its greatest density (39 degrees Fahrenheit).

Completion. Installation of permanent equipment for production of oil or gas, or, in the case of a dry well, reporting to the appropriate authority that the well has been abandoned.

Condensate. A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

Developed oil and gas reserves. Reserves of any category that can be expected to be recovered:

- through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well, and

- through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Development costs. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves;

- drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly;

- acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

- provide improved recovery systems.

Development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole or *well.* An exploratory, development or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or *gross wells.* The total acres or wells, as the case may be, in which a working interest is owned.

MBbls. One thousand barrels of oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet of natural gas.

Mcfe. One thousand cubic feet of natural gas equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

MMBbls. One million barrels of oil or other liquid hydrocarbons.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

Natural gas liquids. The hydrocarbon liquids contained within natural gas.

Net acres or *net wells.* The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.

NYMEX. The New York Mercantile Exchange.

Oil. Crude oil and condensate.

Production costs. Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

- costs of labor to operate the wells and related equipment and facilities;

- repairs and maintenance;

- materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities;

- property taxes and insurance applicable to proved properties and wells and related equipment and facilities; and

- severance taxes.

Productive well. An exploratory, development or extension well that is not a dry well.

Proved 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.

Recompletion. The completion for production of an existing wellbore in another formation from that which the well has been previously completed.

Reserves. Estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reserves.

Standardized measure. 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 Securities and Exchange Commission (the "SEC"), without giving effect to non–property related expenses such as certain general and administrative expenses, debt service and future federal income tax expenses or to depreciation, depletion and amortization and discounted using an annual discount rate of 10%. Our standardized measure includes future obligations under the Texas gross margin tax, but it does not include future federal income tax expenses because we are a partnership and are not subject to federal income taxes.

Successful well. A well capable of producing oil and/or natural gas in commercial quantities.

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

Undeveloped oil and gas reserves. 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.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Workover. Operations on a producing well to restore or increase production.

PART I

ITEM 1. BUSINESS

Overview

EV Energy Partners, L.P. (“we,” “our,” “us” or the “Partnership”) is a publicly held Delaware limited partnership that engages in the acquisition, development and production of oil and natural gas properties. Our general partner is EV Energy GP, L.P. (“EV Energy GP”), a Delaware limited partnership, and the general partner of our general partner is EV Management, LLC (“EV Management”), a Delaware limited liability company. EV Management is a wholly owned subsidiary of EnerVest, Ltd. (“EnerVest”), a Texas limited partnership. EnerVest and its affiliates have a significant interest in us through their 71.25% ownership of EV Energy GP which, in turn, owns a 2% general partner interest in us and all of our incentive distribution rights.

Our common units are traded on the NASDAQ Global Market under the symbol “EVEP.” Our business activities are primarily conducted through wholly owned subsidiaries.

We operate in one reportable segment engaged in the acquisition, development and production of oil and natural gas properties. As of December 31, 2010, our properties were located in the Barnett Shale, the Appalachian Basin (primarily in Ohio and West Virginia), the Mid–Continent areas in Oklahoma, Texas, Arkansas, Kansas and Louisiana, the San Juan Basin, the Monroe Field in Northern Louisiana, the Permian Basin, Central and East Texas (which includes the Austin Chalk area), and Michigan.

Oil and natural gas reserve information is derived from our reserve report prepared by Cawley, Gillespie & Associates, Inc. (“Cawley Gillespie”), our independent reserve engineers. All of our proved oil and natural gas reserves are located in the United States. The following table summarizes information about our proved oil and natural gas reserves by geographic region as of December 31, 2010:

	Estimated Net Proved Reserves				
	Oil (MMBbls)	Natural Gas (Bcf)	Natural Gas Liquids (MMBbls)	Bcfe	PV–10 [(1)] ($ in millions)
Barnett Shale	0.1	218.5	15.2	310.0	$ 299.3
Appalachian Basin	4.7	95.2	–	123.5	213.3
Mid–Continent area	2.8	58.3	0.8	79.7	139.2
San Juan Basin	1.3	43.1	3.8	73.8	85.5
Monroe Field	–	64.7	–	64.7	32.8
Permian Basin	0.9	23.9	5.7	63.4	111.9
Central and East Texas	3.1	23.6	2.0	54.3	109.6
Michigan	–	47.9	–	47.9	34.9
Total	12.9	575.2	27.5	817.3	$ 1,026.5

(1) At December 31, 2010, our standardized measure of discounted future net cash flows was $1,020.2 million. Because we are a limited partnership, we made no provision for federal income taxes in the calculation of standardized measure; however, we made a provision for future obligations under the Texas gross margin tax. The present value of future net pre–tax cash flows attributable to estimated net proved reserves, discounted at 10% per annum (“PV–10”), is a computation of the standardized measure of discounted future net cash flows on a pre–tax basis. PV–10 is computed on the same basis as standardized measure but does not include a provision for federal income taxes or the Texas gross margin tax. PV–10 is considered a non–GAAP financial measure under the regulations of the Securities and Exchange Commission (the “SEC”). We believe PV–10 to be an important measure for evaluating the relative significance of our oil and natural gas properties. We further believe investors and creditors may utilize our PV–10 as a basis for comparison of the relative size and value of our reserves to other companies. PV–10, however, is not a substitute for the standardized measure. Our PV–10 measure and the standardized measure do not purport to present the fair value of our oil and natural gas reserves.

The table below provides a reconciliation of PV–10 to the standardized measure at December 31, 2010 (dollars in millions):

PV–10	$ 1,026.5
Future Texas gross margin taxes, discounted at 10%	(6.3)
Standardized measure	$ 1,020.2

Developments in 2010

Acquisitions and Divestitures

In March 2010 followed by a second closing in June 2010, we, along with certain institutional partnerships managed by EnerVest, acquired oil and natural gas properties in the Appalachian Basin. We acquired a 46.15% proportional interest in these properties for $145.8 million.

In September 2010, we acquired oil and natural gas properties in the Mid–Continent area for $119.9 million, subject to customary closing conditions and purchase price adjustments.

In December 2010, we, along with certain institutional partnerships managed by EnerVest, acquired oil and natural gas properties in the Barnett Shale, including certain related derivatives. We acquired a 31.02% proportional interest in these properties for $295.8 million, subject to customary closing conditions and purchase price adjustments.

In addition to the acquisitions described above, in 2010, we, along with institutional partnerships managed by EnerVest, also acquired oil and natural gas properties in the Appalachian Basin, the San Juan Basin and Central and East Texas for an aggregate purchase price of $7.0 million.

In 2010, we recorded a gain of $40.7 million primarily related to sales of unproved oil and natural gas properties.

Public Offerings

In February 2010, we closed a public offering of 3.45 million common units at an offering price of $28.08 per common unit. We received net proceeds of $94.6 million, including a contribution of $2.0 million by our general partner to maintain its 2% interest in us.

In August 2010, we closed a public offering of 3.45 million of our common units at an offering price of $33.97 per common unit. We received net proceeds of $114.3 million, including a contribution of $2.3 million by our general partner to maintain its 2% interest in us.

Business Strategy

Our primary business objective is to manage our oil and natural gas properties for the purpose of generating cash flows and providing stability and growth of distributions per unit for the long–term benefit of our unitholders. To meet this objective, we intend to execute the following business strategies:

- *Pursue acquisitions of long–lived producing oil and natural gas properties with relatively low decline rates, predictable production profiles, and low– risk development opportunities.*

  Our acquisition program targets oil and natural gas properties that we believe will generate attractive risk-adjusted expected rates of return and that will be financially accretive. These acquisitions are characterized by long–lived production, relatively low decline rates and predictable production profiles, as well as low–risk development opportunities. As part of this strategy, we continually seek to optimize our asset portfolio, which may include the divestiture of noncore assets.

  Our active acquisition efforts may involve our participation in auction processes, as well as situations in which we are the only party or one of a very limited number of potential buyers in negotiations with the potential seller. We finance acquisitions with a combination of cash flow from operations, borrowings under our senior secured credit facility and funds from equity and debt offerings. We also acquire interests in properties alongside the institutional partnerships managed by EnerVest, which allows us to participate in much larger acquisitions than would otherwise be available to us.

- *Reduce cash flow volatility and exposure to commodity price and interest rate risk through commodity price and interest rate derivatives*

  Changes in oil, natural gas, natural gas liquids prices may cause our revenues and cash flows to be volatile. We enter into various derivative contracts intended to achieve more predictable cash flow and to reduce our exposure to fluctuations in the prices of oil, natural gas and natural gas liquids prices. We currently maintain derivative contracts for a significant portion of our oil and natural gas production.

  Our commodity derivatives are primarily in the form of swaps and collars that are designed to provide a fixed price (swaps) or range of prices between a price floor and a price ceiling (collars) that we will receive. Without the use of these commodity derivatives, we would be exposed to the full range of price fluctuations.

  In addition, we enter into derivative contracts in the form of interest rate swaps to minimize the effects of fluctuations in interest rates. However, from time to time we may unwind these interest rate swaps when the current interest rate environment offers better economics. Currently, we utilize London Interbank Offered Rate, or LIBOR, swaps to convert the borrowing rate on indebtedness under our credit facility from a floating rate to a fixed rate.

- *Maximize asset value and cash flow stability through our operating and technical expertise*

  We seek to maintain an inventory of drilling and development projects to maintain and grow our production from our capital development program. EnerVest operates properties representing approximately 93% of our estimated net proved reserves as of December 31, 2010. Our development program is focused on lower–risk, repeatable drilling opportunities to maintain and grow cash flow.

- *Maintain focus on controlling the costs of our operations*

  We focus on controlling the operating costs of our properties. We manage our operating costs by using advanced technologies and integrating the knowledge, expertise and experience of our management teams as well as the managerial and technical staff of EnerVest. Regarding our non–operated properties, we proactively engage with the operators to ensure disciplined and cost focused operations are being implemented.

- *Maintain conservative levels of indebtedness to reduce risk and facilitate acquisition opportunities*

  Since our initial public offering in 2006, we have financed approximately 61% of our $1.3 billion of oil and natural gas property acquisitions with free cash flow and the issuance of common units in public and private offerings. We seek to maintain sufficient liquidity not only for our operating positions but also to maintain flexibility in financing alternatives for completion of our acquisition opportunities.

Competitive Strengths

We believe that we are well positioned to achieve our primary business objective and to execute our strategies because of the following competitive strengths:

- ***Geographically diversified asset base characterized by long–life reserves and predictable decline rates***

  We own a diversified portfolio of oil and natural gas properties, producing from multiple formations in 11 states. Our properties have well understood geologic features, predictable production profiles, and a high percentage of proved developed producing reserves. As of December 31, 2010, approximately 71% of our 817.3 Bcfe of estimated proved reserves were classified as proved developed.

- ***Significant inventory of low–risk development opportunities***

  We have a significant inventory of development projects in our core areas of operation. At December 31, 2010, we had 870 identified drilling locations, of which approximately 659 were proved undeveloped drilling locations and the remainder were unproved drilling locations. In 2010, we drilled a total of 55 gross (9 net) wells with a 95% success rate. Our development program is focused on lower risk drilling opportunities to maintain and increase production.

- ***Relationship with EnerVest***

  We were formed in 2006 by EnerVest, a manager of oil and natural gas assets for institutional investors with an 18 year track record of successfully acquiring and operating oil and gas properties in a wide variety of basins. Our relationship with EnerVest provides us with a wide breadth of operational, financial, technical, risk management and other expertise across a broad geographical range, which assists us in evaluating acquisition and development opportunities.

- ***Experienced management, operating and technical teams***

  Our executive officers and key employees have on average over 25 years of experience in the oil and natural gas industry and over ten years of experience acquiring and managing oil and natural gas properties for EnerVest partnerships.

- ***Substantial hedging through 2014 at attractive average prices***

  We use a combination of swaps and collars to hedge the prices of our oil, natural gas and natural gas liquids production. By removing the price volatility from a significant portion of our production, we have mitigated, but not eliminated, the potential effects of changing commodity prices on our cash flow from operations for the hedged periods.

Our Relationship with EnerVest

One of our principal attributes is our relationship with EnerVest. Through our omnibus agreement, EnerVest agrees to make available its personnel to permit us to carry on our business. We therefore benefit from the technical expertise of EnerVest, which we believe would generally not otherwise be available to a company of our size.

EnerVest's principal business is to act as general partner or manager of EnerVest partnerships that were formed to acquire, explore, develop and produce oil and natural gas properties. A primary investment objective of the EnerVest partnerships is to make periodic cash distributions. EnerVest was formed in 1992, and has acquired for its own account and for the EnerVest partnerships oil and natural gas properties for a total purchase price of more than $4.5 billion, which includes over $1.3 billion related to our acquisitions of oil and natural gas properties. EnerVest acts as an operator of over 18,000 oil and natural gas wells in 12 states.

EnerVest and its affiliates have a significant interest in our partnership through their 71.25% ownership of our general partner, which, in turn, owns a 2% general partner interest in us and all of our incentive distribution rights.

While our relationship with EnerVest is a significant attribute, it is also a source of potential conflicts. For example, we have acquired oil and natural gas properties from partnerships formed by EnerVest and partnerships in which EnerVest has an interest, and we may do so in the future. We have also acquired interests in oil and natural gas properties in conjunction with institutional partnerships managed by EnerVest. In these acquisitions, we and the institutional partnerships managed by EnerVest each acquire an interest in all of the properties subject to the acquisition. The purchase is allocated among us and the institutional partnerships managed by EnerVest based on the interest acquired. In the future, it is possible that we would vary the manner in which we jointly acquire oil and natural gas properties with the institutional partnerships managed by EnerVest.

EnerVest currently operates properties representing 93% of our proved oil and gas reserves as of December 31, 2010. The EnerVest partnerships own interests in the oil and gas properties in which we own interests and which are operated by EnerVest. The properties are primarily located in the Barnett Shale, Central and East Texas and the Appalachian Basin, and these properties represent approximately 52% of our net proved reserves at December 31, 2010. If the EnerVest partnerships were to sell their interests in these properties to a person not affiliated with EnerVest, we may not have a sufficient working interest to cause EnerVest to remain operator of the property. The EnerVest partnerships are under no obligation to us with respect to their sale of the properties they own.

EnerVest is not restricted from competing with us. It may acquire, develop or dispose of oil and natural gas properties or other assets in the future without any obligation to offer us the opportunity to purchase or participate in the development of those assets. In addition, the principal business of the EnerVest partnerships is to acquire and develop oil and natural gas properties. The agreement for one of the current EnerVest partnerships, however, provides that if EnerVest becomes aware, other than in its capacity as an owner of our general partner, of acquisition opportunities that are suitable for purchase by the EnerVest partnership, EnerVest must first offer those opportunities to that EnerVest partnership, in which case we would be offered the opportunities only if the EnerVest partnerships chose not to pursue the acquisition. EnerVest's obligation to offer acquisition opportunities to its existing EnerVest partnership will not apply to acquisition opportunities which we generate internally, and EnerVest has agreed with us that for so long as it controls our general partner it will not enter into any agreements which would limit our ability to pursue acquisition opportunities that we generate internally.

Our Areas of Operation

At December 31, 2010, our properties were located in the Barnett Shale, the Appalachian Basin (primarily in Ohio and West Virginia), the Mid–Continent areas in Oklahoma, Texas, Arkansas, Kansas and Louisiana, the San Juan Basin, the Monroe Field in Northern Louisiana, the Permian Basin, Central and East Texas (which includes the Austin Chalk area), and Michigan.

Barnett Shale

We, along with certain institutional partnerships managed by EnerVest, acquired our Barnett Shale properties in December 2010. The properties are primarily located in Johnson, Parker, Tarrant and Wise counties in Northern Texas. Our portion of the estimated net proved reserves as of December 31, 2010 was 310.0 Bcfe, 70% of which is natural gas. During 2010, we drilled one well and are currently participating in the completion of three others. EnerVest operates wells representing 100% of our estimated net proved reserves in this area, and we own an average 30% working interest in 254 gross productive wells.

Appalachian Basin

We acquired our Appalachian Basin properties at our formation, and we acquired additional properties in the Appalachian Basin, primarily in West Virginia, in December 2007, September 2008, November 2009, March 2010 and June 2010. Our activities are concentrated in the Ohio and West Virginia areas of the Appalachian Basin. Our Ohio area properties are producing primarily from the Clinton formation and other Devonian age sands in 44 counties in Eastern Ohio and 11 counties in Western Pennsylvania. Our West Virginia area properties are producing primarily from the Balltown, Benson and Big Injun formations in 24 counties in North Central West Virginia and one county in Southwestern Pennsylvania. Our estimated net proved reserves as of December 31, 2010 were 123.5 Bcfe, 77% of which is natural gas. During 2010, we drilled nine wells, eight of which were successfully completed. EnerVest operates wells representing 96% of our estimated net proved reserves in this area, and we own an average 40% working interest in 8,260 gross productive wells.

Mid–Continent Area

We acquired our Mid–Continent area properties in December 2006, August 2008, September 2008 and September 2010. The properties are primarily located in 42 counties in Oklahoma, 29 counties in Texas, four parishes in North Louisiana, five counties in Kansas and seven counties in Arkansas. Our estimated net proved reserves as of December 31, 2010 were 79.7 Bcfe, 73% of which is natural gas. During 2010, we drilled 21 wells, all of which were successfully completed. EnerVest operates wells representing 43% of our estimated net proved reserves in this area, and we own an average 21% working interest in 1,647 gross productive wells.

San Juan Basin

We acquired our San Juan Basin properties in September 2008, July 2010 and December 2010. The properties are primarily located in Rio Arriba County, New Mexico and La Plata County in Colorado. Our estimated net proved reserves as of December 31, 2010 were 73.8 Bcfe, 58% of which is natural gas. During 2010, we drilled two wells, both of which were successfully completed. EnerVest operates wells representing 95% of our estimated net proved reserves in this area, and we own an average 75% working interest in 224 gross productive wells.

Monroe Field

We acquired our Monroe Field properties at our formation, and we acquired additional properties in the Monroe Field in March 2007. The properties are located in three parishes in Northeast Louisiana. Our estimated net proved reserves as of December 31, 2010 were 64.7 Bcfe, 100% of which is natural gas. During 2010, we drilled two wells, one of which was successfully completed. EnerVest operates wells representing 100% of our estimated net proved reserves in this area, and we own an average 100% working interest in 3,939 gross productive wells.

Permian Basin

We acquired our Permian Basin properties in October 2007. The properties are primarily located in the Yates, Seven Rivers, Queen, Morrow, Clear Fork and Wichita Albany formations in four counties in New Mexico and Texas. Our estimated net proved reserves as of December 31, 2010 were 63.4 Bcfe, 38% of which is natural gas. During 2010, we did not drill any wells. EnerVest operates wells representing 99% of our estimated net proved reserves in this area, and we own an average 93% working interest in 160 gross productive wells.

Central and East Texas

We, along with certain institutional partnerships managed by EnerVest, acquired our Central and East Texas properties in June 2007, May 2008, August 2008, July 2009, September 2009 and October 2010. The properties are primarily located in the Austin Chalk formation in 13 counties in Central and East Texas, as well as Atascosa and Eastland counties in Texas. Our portion of the estimated net proved reserves as of December 31, 2010 was 54.3 Bcfe, 43% of which is natural gas. During 2010, we drilled 20 wells, 19 of which were successfully completed. EnerVest operates wells representing 96% of our estimated net proved reserves in this area, and we own an average 17% working interest in 1,897 gross productive wells.

Michigan

We acquired our Michigan properties in January 2007, and we acquired additional properties in Michigan in August 2008. The properties are located in the Antrim Shale reservoir in Otsego and Montmorency counties in northern Michigan. Our estimated net proved reserves as of December 31, 2010 were 47.9 Bcfe, 100% of which is natural gas. During 2010, we did not drill any wells. EnerVest operates wells representing 99% of our estimated net proved reserves in this area, and we have an average 86% working interest in 368 gross productive wells.

Our Oil and Natural Gas Data

Our Reserves

The following table presents our estimated net proved oil and natural gas reserves at December 31, 2010:

	Oil (MMBbls)	Natural Gas (Bcf)	Natural Gas Liquids (MMBbls)	Bcfe
Proved reserves:				
Developed	10.9	416.8	16.0	578.0
Undeveloped	2.0	158.4	11.5	239.3
Total	12.9	575.2	27.5	817.3

Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. See “Glossary of Oil and Natural Gas Terms.”

All proved undeveloped locations conform to the SEC rules defining proved undeveloped locations. None of our proved undeveloped reserves as of December 31, 2010 have remained undeveloped for more than five years. We do not have any reserves that would be classified as synthetic oil or synthetic natural gas.

Reserves for proved developed producing wells were estimated using production performance and material balance methods. Certain new producing properties with little production history were forecast using a combination of production performance and analogy to offset production, both of which provide accurate forecasts. Non–producing reserve estimates for both developed and undeveloped properties were forecast using either volumetric and/or analogy methods. These methods provide accurate forecasts due to the mature nature of the properties targeted for development and an abundance of subsurface control data.

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

Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. 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, without giving effect to non–property related expenses such as general and administrative expenses and debt service or to depreciation, depletion and amortization and discounted using an annual discount rate of 10%. Because we are a limited partnership which passes through our taxable income to our unitholders, we have made no provisions for federal income taxes in the calculation of standardized measure; however, we have made a provision for future obligations under the Texas gross margin tax. Standardized measure does not give effect to derivative transactions. The standardized measure shown should not be construed as the current market value of the reserves. The 10% discount factor, which is required by Financial Accounting Standards Board pronouncements, is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

We annually review all proved undeveloped reserves ("PUDs") to ensure an appropriate plan for development exists. We expect to convert our PUDs to proved developed reserves within five years of the date they are first booked as PUDs, except for 13% of our PUDs that require sidetracks of existing producing wells, in which case the development will occur when existing production ceases. At December 31, 2010, we had 239.3 Bcfe of PUDs compared with 25.2 Bcfe of PUDs at December 31, 2009. Of the increase in PUDs at December 31, 2010 compared with December 31, 2009, 188.2 Bcfe is attributable to our acquisition of oil and natural gas properties in the Barnett Shale in December 2010. During 2010, we converted 0.5 Bcfe, or approximately 2%, of our PUDs at December 31, 2009 to proved developed reserves, and we spent approximately $1.8 million related to the development of our PUDs.

Our policies and procedures regarding internal controls over the recording of our oil and natural gas reserves is structured to objectively and accurately estimate our oil and natural gas reserves quantities and present values in compliance with both accounting principles generally accepted in the United States and the SEC's regulations. Compliance with these rules and regulations is the responsibility of our Senior Vice President of Acquisitions, who is also our principal engineer. He has over 27 years of experience in the oil and natural gas industry, with exposure to reserves and reserve related valuations and issues during most of this time, and is a qualified reserves estimator ("QRE"), as defined by the standards of the Society of Petroleum Engineers. Further professional qualifications include a Bachelor of Science, Master of Science and Ph.D. in Petroleum Engineering, extensive internal and external reserve training, asset evaluation and management, and he is a registered professional engineer in the state of Texas. In addition, our principal engineer is an active participant in industry reserve seminars, professional industry groups, is a member of the Society of Petroleum Engineers, spent 13 years as an SPE Technical Editor and has authored several technical papers.

Our controls over reserve estimates included retaining Cawley Gillespie as our independent petroleum engineers. We provided information about our oil and natural gas properties, including production profiles, prices and costs, to Cawley Gillespie and they prepared their own estimates of our oil and natural gas reserves attributable to our properties. All of the information regarding reserves in this annual report on Form 10–K is derived from the report of Cawley Gillespie, which is included as an exhibit to this annual report on Form 10–K. The principal engineer at Cawley Gillespie responsible for preparing our reserve estimates is W. Todd Brooker, a Vice President and Principal with Cawley Gillespie. Mr. Brooker is a licensed professional engineer in the state of Texas (license #83462) with over 20 years of experience in petroleum engineering.

We and EnerVest maintain an internal staff of petroleum engineers, geoscience professionals and petroleum landmen who work closely with Cawley Gillespie to ensure the integrity, accuracy and timeliness of data furnished to Cawley Gillespie in their reserves estimation process. Our Senior Vice President of Acquisitions reviews and approves the reserve information compiled by our internal staff. Our technical team meets regularly with representatives of Cawley Gillespie to review properties and discuss the methods and assumptions used by Cawley Gillespie in their preparation of the year end reserves estimates. Our technical team and Senior Vice President of Acquisitions also meet regularly to review the methods and assumptions used by Cawley Gillespie in their preparation of the year end reserves estimates.

The audit committee of our board of directors meets with management, including the Senior Vice President of Acquisitions, to discuss matters and policies related to our oil and natural gas reserves.

Our Productive Wells

The following table sets forth information relating to the productive wells in which we owned a working interest as of December 31, 2010. 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 productive wells in which we have a working interest, regardless of our percentage interest. A net well is not a physical well, but is a concept that reflects the actual total working interest we hold in a given well. We compute the number of net wells we own by totaling the percentage interests we hold in all our gross wells.

Our wells may produce both oil and natural gas. We classify a well as an oil well if the net equivalent production of oil was greater than natural gas for the well.

	Gross Wells			Net Wells		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
Barnett Shale:						
Operated	–	251	251	–	76	76
Non–operated	–	3	3	–	–	–
Appalachian Basin:						
Operated	1,107	6,516	7,623	492	2,732	3,224
Non–operated	32	605	637	4	86	90
Mid–Continent area:						
Operated	46	241	287	36	166	202
Non–operated	509	851	1,360	43	108	151
San Juan Basin:						
Operated	20	141	161	20	137	157
Non–operated	16	47	63	1	9	10
Monroe Field:						
Operated	–	3,939	3,939	–	3,939	3,939
Non–operated	–	–	–	–	–	–
Permian Basin						
Operated	7	145	152	7	140	147
Non–operated	3	5	8	–	2	2
Central and East Texas:						
Operated	754	803	1,557	215	95	310
Non–operated	69	271	340	3	12	15
Michigan:						
Operated	–	343	343	–	307	307
Non–operated	–	25	25	–	8	8
Total [1]	2,563	14,186	16,749	821	7,817	8,638

(1) In addition, we own small royalty interests in over 890 wells.

Our Developed and Undeveloped Acreage

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

	Developed Acreage		Undeveloped Acreage	
	Gross	**Net**	**Gross**	**Net**
Barnett Shale	20,207	6,110	–	–
Appalachian Basin	508,621	189,654	540,955	110,072
Mid–Continent area)	337,406	100,379	10,437	3,557
San Juan Basin	102,591	35,574	43,857	34,342
Monroe Field [(1)]	6,169	6,169	172,163	147,484
Permian Basin	11,781	11,639	1,560	455
Central and East Texas	972,113	95,592	39,819	4,215
Michigan	27,457	25,822	–	–
Total	1,986,345	470,939	808,791	300,125

(1) There are no spacing requirements on substantially all of the wells on our Monroe Field properties; therefore, one developed acre is assigned to each productive well for which there is no spacing unit assigned.

Substantially all of our developed and undeveloped acreage is held by production, which means that as long as our wells on the acreage continue to produce, we will continue to hold the leases. The leases in which we hold an interest that are not held by production are not material to us.

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, 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 generally 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 leases, we perform title reviews on the most significant leases and, depending on the materiality of the 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 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. Our properties are subject to customary royalty and other interests, liens for current taxes and other burdens that we believe do not materially interfere with the use of or affect our carrying value of the properties.

Our Drilling Activity

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

The following table summarizes our approximate gross and net interest in development wells completed by us during 2010, 2009 and 2008, regardless of when drilling was initiated. 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.

	Year Ended December 31,		
	2010	**2009**	**2008**
Gross wells:			
Productive	52.0	30.0	58.0
Dry	3.0	–	2.0
Total	55.0	30.0	60.0
Net wells:			
Productive	7.9	6.1	28.2
Dry	1.2	–	2.0
Total	9.1	6.1	30.2

As of December 31, 2010, we were participating in the drilling of seven gross (1.5 net) development wells.

We drilled three gross (0.3 net) exploratory wells in 2010, two of which were successfully completed as producers. We did not drill any exploratory wells in 2009 and 2008.

Well Operations

We have entered into operating agreements with EnerVest. Under these operating agreements, EnerVest acts as contract operator of the oil and natural gas wells and related gathering systems and production facilities in which we own an interest, if our interest entitles us to control the appointment of the operator of the well, gathering system or production facilities. As contract operator, EnerVest designs and manages the drilling and completion of our wells and manages the day to day operating and maintenance activities for our wells.

Under these operating agreements, EnerVest has established a joint account for each well in which we have an interest. We are required to pay our working interest share of amounts charged to the joint account. The joint account is charged with all direct expenses incurred in the operation of our wells and related gathering systems and production facilities. The determination of which direct expenses can be charged to the joint account and the manner of charging direct expenses to the joint account for our wells is done in accordance with the Council of Petroleum Accountants Societies (“COPAS”) model form of accounting procedure.

Under the COPAS model form, direct expenses include the costs of third party services performed on our properties and wells, as well as gathering and other equipment used on our properties. In addition, direct expenses include the allocable share of the cost of services performed on our properties and wells by EnerVest employees. The allocation of the cost of EnerVest employees who perform services on our properties is based on time sheets maintained by EnerVest’s employees. Direct expenses charged to the joint account also include an amount determined by EnerVest to be the fair rental value of facilities owned by EnerVest and used in the operation of our properties.

Principal Customers and Marketing Arrangements

The market for our oil, natural gas and natural gas liquids production depends on factors beyond our control, including the extent of domestic production and imports of oil, natural gas and natural gas liquids, the proximity and capacity of natural gas pipelines and other transportation facilities, the demand for oil, natural gas and natural gas liquids, the marketing of competitive fuels and the effect of state and federal regulation. The oil and natural gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers.

Our oil, natural gas and natural gas liquids production is sold to a variety of purchasers. The terms of sale under the majority of existing contracts are short–term, usually one year or less in duration. The prices received for oil, natural gas and natural gas liquids sales are generally tied to monthly or daily indices as quoted in industry publications.

In 2010 and 2009, no customer accounted for greater than 10% of our consolidated oil, natural gas and natural gas liquids revenues. In 2008, Southern Union Gas Services, Enbridge Marketing (U.S.), L.P. and CMS Energy Corporation accounted for 11%, 10% and 10%, respectively, of our consolidated oil, natural gas and natural gas liquids revenues. We believe that the loss of a major customer would have a temporary effect on our revenues but that over time, we would be able to replace our major customers.

Competition

The oil and natural gas industry is highly competitive. We encounter strong competition from other independent operators and from major oil and natural gas companies in acquiring properties, contracting for drilling equipment and securing trained personnel. Many of these competitors have financial and technical resources and staffs substantially larger than ours. 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 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 have delayed development drilling and other exploitation activities and have caused significant price increases. We are unable to predict when, or if, such shortages may occur or how they would affect our development and exploitation program.

Competition is also strong for attractive oil and natural gas producing properties, undeveloped leases and drilling rights, and there can be no assurances that we will be able to compete satisfactorily when attempting to make further acquisitions.

Seasonal Nature of Business

Seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other operations primarily in certain areas of the Appalachian Basin, the San Juan Basin and Michigan. As a result, we generally perform the majority of our drilling in these areas during the summer and autumn months. In addition, the Monroe Field properties in Louisiana are subject to flooding. These seasonal anomalies can pose challenges for meeting our drilling objectives and increase competition for equipment, supplies and personnel during the drilling season, which could lead to shortages and increased costs or delay our operations. Generally demand for natural gas is higher in summer and winter months. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter natural gas requirements during off–peak months. This can also lessen seasonal demand fluctuations.

Environmental, Health and Safety Matters and Regulation

Our operations are subject to stringent and complex federal, state and local laws and regulations that govern the protection of the environment as well as the discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- require the installation of pollution control equipment in connection with operations;
- place restrictions or regulations upon the use of the material based on our operations;
- restrict the types, quantities and concentrations of various substances that can be released into the environment or used in connection with drilling, production and transportation activities;
- limit or prohibit drilling activities on lands lying within wilderness, wetlands and other protected areas;
- require remedial measures to mitigate pollution from former and ongoing operations, such as site restoration, pit closure and plugging of abandoned wells; and
- require the expenditure of significant amounts in connection with worker health and safety.

These laws, rules and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal, state and local agencies frequently revise environmental laws and regulations, and such changes could result in increased costs for environmental compliance, such as waste handling, permitting, or cleanup for the oil and natural gas industry and could have a significant impact on our operating costs.

The following is a summary of some of the existing laws, rules and regulations to which our business operations are subject.

Solid and Hazardous Waste Handling

The federal Resource Conservation and Recovery Act, or RCRA, and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous solid waste. Although oil and natural gas waste generally is exempt from regulations as hazardous waste under RCRA, we generate waste as a routine part of our operations that may be subject to RCRA. Although a substantial amount of the waste generated in our operations are regulated as non–hazardous solid waste rather than hazardous waste, there is no guarantee that the EPA or individual states will not adopt more stringent requirements for the handling of non–hazardous waste or categorize some non–hazardous waste as hazardous in the future. Any such change could result in an increase in our costs to manage and dispose of waste, which could have a material adverse effect on our results of operations and financial position.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, imposes joint and several liability for costs of investigation and remediation and for natural resource damages without regard to fault or legality of the original conduct, on certain classes of persons with respect to the release into the environment of substances designated under CERCLA as hazardous substances. These classes of persons, or so–called potentially responsible parties include the current and past owners or operators of a site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance found at the site. CERCLA also authorizes the Environmental Protection Agency, or EPA, and, in some instances, third parties to take actions in response to threats to public health or the environment and to seek to recover from the PRPs the costs of such action. Many states have adopted comparable or more stringent state statutes.

Although CERCLA generally exempts “petroleum” from the definition of hazardous substance, in the course of our operations, we have generated and will generate wastes that may fall within CERCLA’s definition of hazardous substance and may have disposed of these wastes at disposal sites owned and operated by others. We may also be the owner or operator of sites on which hazardous substances have been released. To our knowledge, neither we nor our predecessors have been designated as a PRP by the EPA under CERCLA; we also do not know of any prior owners or operators of our properties that are named as PRPs related to their ownership or operation of such properties. In the event contamination is discovered at a site on which we are or have been an owner or operator or to which we sent hazardous substances, we could be liable for the costs of investigation and remediation and natural resources damages.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production for many years. Although we believe we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including offsite locations, where such substances have been taken for disposal. In addition, some of these properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons were not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. In the future, we could be required to remediate property, including groundwater, containing or impacted by previously disposed wastes (including wastes disposed or released by prior owners or operators, or property contamination, including groundwater contamination by prior owners or operators) or to perform remedial plugging operations to prevent future or mitigate existing contamination.

Clean Water Act

The Federal Water Pollution Control Act, also known as the “Clean Water Act” and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of produced water and other oil and natural gas wastes, into state waters and 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 an analogous state agency. 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, as well as require remedial or mitigation measures, for non–compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. In the event of an unauthorized discharge of wastes, we may be liable for penalties and cleanup and response costs.

Safe Drinking Water Act and Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing activities are typically regulated by state oil and gas commissions but not at the federal level, as the federal Safe Drinking Water Act expressly excludes regulation of these fracturing activities. Due to public concerns raised regarding potential impacts of hydraulic fracturing on groundwater quality, there have been recent developments at the federal and state levels that could result in regulation of hydraulic fracturing becoming more stringent and costly. 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. In addition, a committee of the U.S. House of Representatives is conducting an investigation of hydraulic fracturing practices. Moreover, legislation was introduced in the recently completed session of Congress to provide for federal regulation of hydraulic fracturing by eliminating the current exemption in the Safe Drinking Water Act, and, further, to require disclosure of the chemicals used in the fracturing process, and similar legislation could be introduced in the current session of Congress that convened on January 3, 2011. Also, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. For example, New York has imposed a de facto moratorium on the issuance of permits for high-volume, horizontal hydraulic until state-administered environmental studies are finalized, a draft of which must be published by June 1, 2011, followed by a 30-day comment period. Further, Pennsylvania has adopted a variety of regulations limiting how and where fracturing can be performed and Wyoming has adopted legislation requiring drilling operators conducting hydraulic fracturing activities in that state to publicly disclose the chemicals used in the fracturing process. If new laws or regulations imposing significant restrictions or conditions on hydraulic fracturing activities are adopted in areas where we conduct business, we could incur substantial compliance costs and such requirements could adversely delay or restrict our ability to conduct fracturing activities on our assets.

Oil Pollution Act

The primary federal law for oil spill liability is the Oil Pollution Act, or OPA, which amends and augments oil spill provisions of the Clean Water Act and imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters or adjoining shorelines. A liable "responsible party" includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge, or in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. OPA assigns joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses exist to the liability imposed by OPA, they are limited. In the event of an oil discharge or substantial threat of discharge, we may be liable for costs and damages.

Air Emissions

Our operations are subject to the federal Clean Air Act, or CAA, and analogous state laws and local ordinances governing the control of emissions from sources of air pollution. The CAA and analogous state laws require new and modified sources of air pollutants to obtain permits prior to commencing construction. Major sources of air pollutants are subject to more stringent, federally imposed requirements including additional permits. Federal and state laws designed to control hazardous (or toxic) air pollutants, might require installation of additional controls. Administrative enforcement actions for failure to comply strictly with air pollution regulations or permits are generally resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could bring lawsuits for civil penalties or require us to forego construction, modification or operation of certain air emission sources.

National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands may be subject to the National Environmental Policy Act, or NEPA, which 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 prepare an Environmental Assessment that assesses 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. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay or impose additional conditions upon the development of oil and natural gas projects.

Climate Change Legislation

More stringent laws and regulations relating to climate change and greenhouse gases ("GHGs") may be adopted in the future and could cause us to incur material expenses in complying with them. The EPA has been moving forward to regulate GHGs as pollutants under the CAA and has already adopted rules establishing GHG emission limits from motor vehicles beginning with the 2012 model year. As a result, the EPA, as of January 2, 2011, requires the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration ("PSD") and Title V permitting programs in a multi-step process, with the largest sources first subject to permitting. Some states, regions and localities have adopted or have considered programs to address GHG emissions. In addition, both houses of Congress actively considered legislation to reduce emissions of greenhouse gases and many states have adopted or considered measures to establish GHG emissions reduction levels, often involving the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions or major producers of fuels to acquire and surrender emission allowances. Federal efforts at a cap and trade program appear to not be moving forward in Congress. Some members of Congress have publicly indicated an intention to introduce legislation to curb EPA's regulatory authority over GHGs. Depending on the regulatory reach of new CAA legislation implementing regulations or new EPA and/or state, regional or local rules restricting the emission of GHGs, we could incur significant costs to control our emissions and comply with regulatory requirements. In addition, in October 2009, the EPA has adopted a mandatory GHG emissions reporting program which imposes reporting and monitoring requirements on various industries and in November 2010, expanded this GHG reporting rule to include onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities. We do not believe that our compliance with applicable monitoring, recordkeeping and reporting requirements under the reporting rule as recently amended will have a material adverse effect on our results of operations or financial position. Significant financial expenditures could be required to comply with the monitoring, recordkeeping and reporting requirements under the EPA's GHG reporting program. We do not believe, however, that our compliance with applicable monitoring, recordkeeping and reporting requirements under GHG reporting program as recently amended will have a material adverse effect on our results of operations or financial position.

Because of the lack of any comprehensive legislative program addressing GHGs, there is a great deal of uncertainty as to how and when federal regulation of GHGs might take place. Moreover, the federal, regional, state and local regulatory initiatives also could adversely affect the marketability of the oil and natural gas we produce. The impact of such future programs cannot be predicted, but we do not expect our operations to be affected any differently than other similarly situated domestic competitors.

OSHA and Other Laws and Regulation

We are subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes. These laws and the implementing regulations strictly govern the protection of the health and safety of employees. The OSHA hazard communication standard, the EPA community right–to–know regulations under the Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in substantial compliance with these applicable requirements and with other OSHA and comparable requirements.

We believe that we are in substantial compliance with all existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. We did not incur any material capital expenditures for remediation or pollution control activities for the years ended December 31, 2010, 2009 and 2008. Additionally, 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 in the future. However, we cannot assure you that the passage of more stringent laws and regulations in the future will not have a negative impact our business activities, financial condition, results of operations or ability to pay distributions to our unitholders.

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.

Legislation continues to be introduced in Congress and development of regulations continues in the Department of Homeland Security and other agencies concerning the security of industrial facilities, including natural gas and oil facilities. Our operations may be subject to such laws and regulations. Presently, it is not possible to accurately estimate the costs we could incur to comply with any such facility security laws or regulations, but such expenditures could be substantial.

Drilling and Production

Statutes, rules and regulations affecting exploration and production undergo constant review and often are amended, expanded and reinterpreted, making the prediction of future costs or the impact of regulatory compliance to new laws and statute difficult. The regulatory burden on the oil and natural gas industry increases its cost of doing business and, consequently, affects its profitability. 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 and federal regulations are generally intended to prevent waste of oil and natural gas, protect correlative rights to produce oil and natural gas between owners in a common reservoir or formation, control the amount of oil and natural gas produced by assigning allowable rates of production and control contamination of the environment. Pipelines and natural gas plants operated by other companies that provide midstream services to us are also subject to the jurisdiction of various federal, state and county/municipal agencies, which can affect our operations. State laws also regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. States in the Appalachian Basin have taken up consideration of forced pooling. Other states rely on voluntary pooling of lands and leases.

States generally impose a production, ad valorem or severance tax with respect to the production and sale of oil and natural gas within its jurisdiction. States do not generally regulate wellhead prices or engage in other, similar direct economic regulation, but there can be no assurance they will not do so in the future.

In addition, 11 states have enacted surface damage statutes (“SDAs”). These laws are designed to compensate for damage caused by mineral development. Most SDAs contain entry notification and negotiation requirements to facilitate contact between operators and surface owners/users. Most also contain bonding requirements and specific expenses for exploration and producing activities. Costs and delays associated with SDAs could impair operational effectiveness and increase development costs.

We do not control the availability of transportation and processing facilities used in the marketing of our production. For example, we may have to shut–in a productive natural gas well because of a lack of available natural gas gathering or transportation facilities.

If we conduct operations on federal, state or Indian oil and natural gas leases, these operations must comply with numerous regulatory restrictions, including various non–discrimination statutes, royalty and related valuation requirements, and certain of these operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by the Bureau of Land Management, Minerals Management Service or other appropriate federal or state agencies.

Federal Natural Gas Regulation

The availability, terms and cost of transportation significantly affect sales of natural gas. The interstate transportation and sale for resale of natural gas are subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission (“FERC”). Federal and state regulations govern the price and terms for access to natural gas pipeline transportation. FERC’s regulations for interstate natural gas transmission in some circumstances may also affect the intrastate transportation of natural gas. FERC regulates the rates, terms and conditions applicable to the interstate transportation of natural gas by pipelines under the Natural Gas Act as well as under Section 311 of the Natural Gas Policy Act.

Since 1985, FERC has implemented regulations intended to increase competition within the natural gas industry by making natural gas transportation more accessible to natural gas buyers and sellers on an open-access, nondiscriminatory basis. FERC has announced several important transportation related policy statements and rule changes, including a statement of policy and final rule issued February 25, 2000, concerning alternatives to its traditional cost-of-service rate-making methodology to establish the rates interstate pipelines may charge for their services. The final rule revises FERC’s pricing policy and current regulatory framework to improve the efficiency of the market and further enhance competition in natural gas markets.

FERC has also issued several other generally pro–competitive policy statements and initiatives affecting rates and other aspects of pipeline transportation of natural gas. On May 31, 2005, FERC generally reaffirmed its policy of allowing interstate pipelines to selectively discount their rates in order to meet competition from other interstate pipelines. On June 15, 2006, the FERC issued an order in which it declined to establish uniform standards for natural gas quality and interchangeability, opting instead for a pipeline–by–pipeline approach. On June 19, 2006, in order to facilitate development of new storage capacity, FERC established criteria to allow providers to charge market–based (*i.e.* negotiated) rates for storage services. On June 19, 2008, the FERC removed the rate ceiling on short–term releases by shippers of interstate pipeline transportation capacity.

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

State Natural Gas Regulation

Various states regulate the drilling for, and the production, gathering and sale of, natural gas, including imposing severance taxes and requirements for obtaining drilling permits. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of natural gas resources. States may regulate rates of production and may establish maximum daily production allowables from natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that they will not do so in the future. The effect of these regulations may be to limit the amounts of natural gas that may be produced from our wells and to limit the number of wells or locations we can drill.

Other Regulation

In addition to the regulation of oil and natural gas pipeline transportation rates, the oil and natural gas industry generally is subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to occupational safety, resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect upon our unitholders.

Employees

EV Management, the general partner of our general partner, has five full time employees and two executive officers who spend a significant amount of their time on our operations. At December 31, 2010, EnerVest, the sole member of EV Management, had approximately 700 full–time employees, including over 70 geologists, engineers and land professionals. To carry out our operations, EnerVest employs the people who will provide direct support to our operations. None of these employees are covered by collective bargaining agreements. We consider EV Management’s relationship with its employees to be good, and EnerVest considers its relationship with its employees to be good.

Offices

We do not have any owned or leased property (other than our interests in oil and gas properties). Under our omnibus agreement, EnerVest provides us office space for our executive officers and other employees at EnerVest's offices in Houston, Texas.

Available Information

Our annual reports on Form 10–K, quarterly reports on Form 10–Q, current reports on Form 8–K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), are made available free of charge on our website at www.evenergypartners.com as soon as reasonably practicable after these reports have been electronically filed with, or furnished to, the SEC. These documents are also available on the SEC's website at www.sec.gov or you may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington DC 20549. Our website also includes our Code of Business Conduct and the charters of our audit committee and compensation committee. No information from either the SEC's website or our website is incorporated herein by reference.

ITEM 1A. RISK FACTORS

Limited partner interests are inherently different from capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in similar businesses. If any of the following risks were actually to occur, our business, financial condition or results of operations or cash flows could be materially adversely affected.

Risks Related to Our Business

We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner, to enable us to make cash distributions to holders of our common units at the current distribution rate under our cash distribution policy.

In order to make our cash distributions at our current quarterly distribution rate of $0.759 per common unit, we will require available cash of approximately $26.5 million per quarter based on the common units outstanding as of February 18, 2011. We may not have sufficient available cash from operating surplus each quarter to enable us to make cash distributions at this anticipated quarterly distribution rate under our cash distribution policy. The amount of cash we can distribute on our 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 and natural gas we produce;
- the prices at which we sell our oil and natural gas production;
- our ability to acquire additional oil and natural gas properties at economically attractive prices;
- our ability to hedge commodity prices;
- the level of our capital expenditures;
- the level of our operating and administrative costs; and
- the level of our interest expense, which depends on the amount of our indebtedness and the interest payable thereon.

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 amount of cash reserves established by our general partner for the proper conduct of our business and for capital expenditures to maintain our production levels over the long–term, which may be substantial;
- the cost of acquisitions;

- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- the timing and collectability of receivables; and
- prevailing economic conditions.

As a result of these factors, the amount of cash we distribute to our unitholders may fluctuate significantly from quarter to quarter and may be less than the quarterly distribution amount that we expect to distribute.

If oil and natural gas prices remain depressed for a prolonged period, our cash flows from operations will decline and we may have to lower our distributions or may not be able to pay distributions at all.

Our revenue, profitability and cash flow depend upon the prices for oil and natural gas. The prices we receive for oil and natural gas production are volatile and a drop in prices can significantly affect our financial results and impede our growth, including our ability to maintain or increase our borrowing capacity, to repay current or future indebtedness and to obtain additional capital on attractive terms, all of which can affect our ability to pay distributions. Changes in oil and natural gas prices have a significant impact on the value of our reserves and on our cash flows. Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control, such as:

- the domestic and foreign supply of and demand for oil and natural gas;
- the amount of added production from development of unconventional natural gas reserves;
- the price and quantity of foreign imports of oil and natural gas;
- the level of consumer product demand;
- weather conditions;
- the value of the U.S dollar relative to the currencies of other countries;
- overall domestic and global economic conditions;
- political and economic conditions and events in foreign oil and natural gas producing countries, including embargoes, continued hostilities in the Middle East and other sustained military campaigns, conditions in South America, China and Russia, and acts of terrorism or sabotage;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations and taxation;
- the impact of energy conservation efforts;
- the proximity and capacity of natural gas pipelines and other transportation facilities to our production; and
- the price and availability of alternative fuels.

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

We currently own interests in oil and natural gas properties in which partnerships managed by EnerVest also own an interest and we may acquire properties in which the EnerVest managed partnerships own an interest in the future. If the EnerVest partnerships elect to sell their interest in these properties, we would own a minority interest in the properties, and EnerVest may lose the ability to operate the properties.

We own interests in oil and natural gas properties in which institutional partnerships managed by EnerVest also own interests. These properties are primarily in the Barnett Shale, Central and East Texas and the Appalachian Basin, and these properties represent approximately 52% of our estimated net proved reserves as of December 31, 2010. In addition, we expect to make acquisitions of properties jointly with the EnerVest institutional partnerships in the future. If the EnerVest partnerships were to sell their interest in these properties to a person not affiliated with EnerVest, we might not have a sufficient working interest to cause EnerVest to remain operator of the property. Loss of operations would mean that EnerVest would no longer control decisions regarding the development and production of those properties, and any replacement operator could make decisions regarding development or production activities that make it difficult to implement our strategy.

We depend on EnerVest to provide us services necessary to operate our business. If EnerVest were unable or unwilling to provide these services, it would result disruption in our business which could have an adverse effect on our ability to make cash distributions to our unitholders.

Under an omnibus agreement, EnerVest provides services to us such as accounting, human resources, office space, and other administrative services, and under an operating agreement, EnerVest operates our properties for us. If EnerVest were to become unable or unwilling to provide such services, we would need to develop these services internally or arrange for the services from another service provider. Developing the capabilities internally or by retaining another service provider could have an adverse effect on our ability make cash distributions to our unitholders and our business, and the services, when developed or retained, may not be of the same quality as provided to us by EnerVest.

Our hedging transactions expose us to counterparty credit risk.

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. To mitigate counterparty credit risk, we conduct our hedging activities with financial institutions who are lenders under our credit facility. Disruptions in the financial markets could lead to sudden changes in a counterparty's liquidity, which could impair their ability to perform under the terms of the derivative contract. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions.

During periods of falling commodity prices, such as in late 2008, our hedge receivable positions increase, which increases our exposure. If the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss.

The adoption of derivatives legislation and regulations related to derivative contracts could have an adverse impact on our ability to hedge risks associated with our business.

On July 21, 2010, the President signed into law the Dodd–Frank Wall Street Reform and Consumer Protection Act (the "Act"). Among other things, the Act requires the Commodity Futures Trading Commission and the SEC to enact regulations affecting derivative contracts, including the derivative contracts we use to hedge our exposure to price volatility within 360 days from the date of enactment. We cannot predict the content of these regulations or the effect that these regulations will have on our hedging activities. Of particular concern, the Act does not explicitly exempt end users (such as us) from the requirements to use exchanges, which would require us to post margin in connection with hedging activities. Even if we qualify for an exception, there are other aspects of the Act that may make it more expensive for other parties to offer these hedges to us. The full effects of the Act will not be known until the regulations have been enacted and the market for these hedges has adjusted. It is possible the hedges will become more expensive, uneconomic or unavailable, which could lead to increased costs or commodity price volatility or a combination of both.

The distressed financial conditions of customers could have an adverse impact on us in the event these customers are unable to pay us for the products or services we provide.

Some of our customers may experience, in the future, severe financial problems that have had or may have a significant impact on their creditworthiness. We cannot provide assurance that one or more of our financially distressed customers will not default on their obligations to us or that such a default or defaults will not have a material adverse effect on our business, financial position, future results of operations or future cash flows. Furthermore, the bankruptcy of one or more of our customers, or some other similar proceeding or liquidity constraint, might make it unlikely that we would be able to collect all or a significant portion of amounts owed by the distressed entity or entities. In addition, such events might force such customers to reduce or curtail their future use of our products and services, which could have a material adverse effect on our results of operations and financial condition.

We may be unable to integrate successfully the operations of our recent or future acquisitions with our operations and we may not realize all the anticipated benefits of the recent acquisitions or any future acquisition.

Integration of our recent acquisitions with our business and operations has been a complex, time consuming and costly process. Failure to successfully assimilate our past or future acquisitions could adversely affect our financial condition and results of operations.

Our acquisitions involve numerous risks, including:

- operating a significantly larger combined organization and adding operations;
- difficulties in the assimilation of the assets and operations of the acquired business, especially if the assets acquired are in a new business segment or geographic area;
- the risk that oil and natural gas reserves acquired may not be of the anticipated magnitude or may not be developed as anticipated;
- the loss of significant key employees from the acquired business:
- the diversion of management’s attention from other business concerns;
- the failure to realize expected profitability or growth;
- the failure to realize expected synergies and cost savings;
- coordinating geographically disparate organizations, systems and facilities; and
- coordinating or consolidating corporate and administrative functions.

Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. If we consummate any future acquisition, our capitalization and results of operation may change significantly, and you may not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in evaluating future acquisitions.

Unless we replace the oil and natural gas reserves we produce, our revenues and production will decline, which would adversely affect our cash flows from operations and our ability to make distributions to our unitholders.

Producing reservoirs are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our decline rate may change when we drill additional wells, make acquisitions or under other circumstances. Our future cash flows and income and our ability to maintain and to increase distributions to unitholders are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs, which would adversely affect our business, financial condition and results of operations. Factors that may hinder our ability to acquire additional reserves include competition, access to capital, prevailing oil and natural gas prices and the number and attractiveness of properties for sale.

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

Numerous uncertainties are inherent in estimating quantities of oil and natural gas reserves. Our estimates of our net proved reserve quantities are based upon reports from Cawley Gillespie, an independent petroleum engineering firm used by us. The process of estimating oil and natural gas reserves is complex, requiring significant decisions and assumptions in the evaluation of available geological, engineering and economic data for each reservoir, and these reports rely upon various assumptions, including assumptions regarding 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. Over time, we may make material changes to reserve estimates taking into account the results of actual drilling and production. Any significant variance in our assumptions and actual results could greatly affect our estimates of reserves, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery, and estimates of the future net cash flows. In addition, our wells are characterized by low production rates per well. As a result, changes in future production costs assumptions could have a significant effect on our proved reserve quantities.

The standardized measure of discounted future net cash flows of our estimated net proved reserves is not necessarily the same as the current market value of our estimated net proved reserves. We base the discounted future net cash flows from our estimated net proved reserves on average prices for the 12 months preceding the date of the estimate. Actual prices received for production and actual costs of such production will be different than these assumptions, perhaps materially.

The timing of both our production and our incurrence of expenses in connection with the development and production of our 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 inaccuracy in our 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 our unitholders.

The SEC amended the definition of proved reserves for all reserves estimated included in filings after January 1, 2010. As a result, our estimates of proved reserves filed in reports prior to January 1, 2010 will not be comparable to reports filed after that date, including those in this annual report.

Our acquisition and development operations will 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 production and reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the development, production and acquisition of oil and natural gas reserves. These expenditures will be deducted from our revenues in determining our cash available for distribution. We intend to finance our future capital expenditures with cash flows from operations, borrowings under our credit facility and the issuance of debt and equity securities. The incurrence of debt will require that a portion of our cash flows from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flows to fund working capital, capital expenditures and acquisitions. Our cash flows from operations and access to capital are subject to a number of variables, including:

- the estimated quantities of our oil and natural gas reserves;
- the amount of oil and natural gas we produce from existing wells;

- the prices at which we sell our production; and

- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our credit facility decrease as a result of lower commodity 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. Our credit facility may restrict our ability to obtain new 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 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, which could lead to a decline in our oil and natural gas reserves, and could adversely affect our business, results of operation, financial conditions and ability to make distributions to our unitholders. In addition, we may lose opportunities to acquire oil and natural gas properties and businesses.

We will rely on development drilling to assist in maintaining our levels of production. If our development drilling is unsuccessful, our cash available for distributions and financial condition will be adversely affected.

Part of our business strategy will focus on maintaining production levels by drilling development wells. Although we were successful in development drilling in the past, we cannot assure you that we will continue to maintain production levels through development drilling. Our drilling involves numerous risks, including the risk that we will not encounter commercially productive oil or natural gas reservoirs. We must incur significant expenditures to drill and complete wells. Additionally, seismic technology does not allow us to know conclusively, prior to drilling a well, that oil or natural gas is present or economically producible. The costs of drilling and completing wells are often uncertain, and it is possible that we will make substantial expenditures on development drilling and not discover reserves in commercially viable quantities. These expenditures will reduce cash available for distribution to our unitholders.

Our drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors, including:

- unexpected drilling conditions;

- facility or equipment failure or accidents;

- shortages or delays in the availability of drilling rigs and equipment;

- adverse weather conditions;

- compliance with environmental and governmental requirements;

- title problems;

- unusual or unexpected geological formations;

- pipeline ruptures;

- fires, blowouts, craterings and explosions; and
- uncontrollable flows of oil or natural gas or well fluids.

Properties that we buy may not produce as projected and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against such liabilities, which could adversely affect our cash available for distribution.

One of our growth strategies is to capitalize on opportunistic acquisitions of oil and natural gas reserves. Any future acquisition will require an assessment of recoverable reserves, title, future oil and natural gas prices, operating costs, potential environmental hazards, potential tax and ERISA liabilities, and other liabilities and similar factors. Ordinarily, our review efforts are focused on the higher valued properties and are inherently incomplete because it generally is not feasible to review in depth every individual property involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and potential problems, such as ground water contamination and other environmental conditions and deficiencies in the mechanical integrity of equipment are not necessarily observable even when an inspection is undertaken. Any unidentified problems could result in material liabilities and costs that negatively impact our financial conditions and results of operations and our ability to make cash distributions to our unitholders.

Additional potential risks related to acquisitions include, among other things:

- incorrect assumptions regarding the future prices of oil and natural gas or the future operating or development costs of properties acquired;
- incorrect estimates of the oil and natural gas reserves attributable to a property we acquire;
- an inability to integrate successfully the businesses we acquire;
- the assumption of liabilities;
- limitations on rights to indemnity from the seller;
- the diversion of management's attention from other business concerns; and
- losses of key employees at the acquired businesses.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly.

Our hedging activities could result in financial losses or could reduce our net income, which may adversely affect our ability to pay cash distributions to our unitholders.

To achieve more predictable cash flows and to reduce our exposure to fluctuations in the prices of oil and natural gas, we have and may continue to enter into hedging arrangements for a significant portion of our oil and natural gas production. If we experience a sustained material interruption in our production, we might be forced to satisfy all or a portion of our hedging obligations without the benefit of the cash flows from our sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity. Lastly, an attendant risk exists in hedging activities that the counterparty in any derivative transaction cannot or will not perform under the instrument and that we will not realize the benefit of the hedge.

Our ability to use hedging transactions to protect us from future oil and natural gas price declines will be dependent upon oil and natural gas prices at the time we enter into future hedging transactions and our future levels of hedging, and as a result our future net cash flows may be more sensitive to commodity price changes.

Our policy has been to hedge a significant portion of our near–term estimated oil and natural gas production. However, our price hedging strategy and future hedging transactions will be determined at the discretion of our general partner, which is not under an obligation to hedge a specific portion of our production. The prices at which we hedge our production in the future will be dependent upon commodities prices at the time we enter into these transactions, which may be substantially higher or lower than current oil and natural gas prices. Accordingly, our price hedging strategy may not protect us from significant declines in oil and natural gas prices received for our future production. Conversely, our hedging strategy may limit our ability to realize cash flows from commodity price increases. It is also possible that a substantially larger percentage of our future production will not be hedged as compared with the next few years, which would result in our oil and natural gas revenues becoming more sensitive to commodity price changes.

We may be unable to compete effectively with larger companies, which may adversely affect our ability to generate sufficient revenue and our ability 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 than us. 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 and natural gas, 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 and natural gas prices, to contract for drilling equipment, to secure trained personnel, and to absorb the burden of present and future federal, state, local and other laws and regulations. The oil and natural gas industry has periodically experienced shortages of drilling rigs, equipment, pipe and personnel, which has delayed development drilling and other exploitation activities and has caused significant price increases. Competition has been strong in hiring experienced personnel, particularly in the accounting and financial reporting, tax and land departments. In addition, competition is strong for attractive oil and natural gas producing properties, oil and natural gas companies, and undeveloped leases and drilling rights. We may be often outbid by competitors in our attempts to acquire properties or companies. Our inability to compete effectively with larger companies could have a material adverse impact on our business activities, financial condition and results of operations.

Our business is subject to operational risks that will not be fully insured, which, if they were to occur, could adversely affect our financial condition or results of operations and, as a result, our ability to pay distributions to our unitholders.

Our business activities are subject to operational risks, including:

- damages to equipment caused by adverse weather conditions, including hurricanes and flooding;
- facility or equipment malfunctions;
- pipeline ruptures or spills;
- fires, blowouts, craterings and explosions; and
- uncontrollable flows of oil or natural gas or well fluids.

In addition, a portion of our natural gas production is processed to extract natural gas liquids at processing plants that we own or that are owned by others. If these plants were to cease operations for any reason, we would need to arrange for alternative transportation and processing facilities. These alternative facilities may not be available, which could cause us to shut–in our natural gas production, or the alternative facilities could be more expensive than the facilities we currently use.

Any of these events could adversely affect our ability to conduct operations or cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution or other environmental contamination, loss of wells, regulatory penalties, suspension of operations, and attorney’s fees and other expenses incurred in the prosecution or defense of litigation.

As is customary in the industry, we maintain insurance against some but not all of these risks. 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, results of operations and ability to pay distributions to our unitholders.

Our ability to make distributions to our unitholders and to pursue our business strategies may be adversely affected if we incur costs and liabilities due to a failure to comply with environmental regulations or a release of hazardous substances into the environment.

We may incur significant costs and liabilities as a result of environmental requirements applicable to the operation of our wells, gathering systems and other facilities. These costs and liabilities could arise under a wide range of federal, state and local environmental laws and regulations, including, for example:

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

- the Resource Conservation and Recovery Act, or RCRA, and comparable state laws that impose requirements for the handling and disposal of waste from our facilities;

- the 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 waste for disposal;

- the OPA which subject responsible parties to liability for removal costs and damages arising from an oil spill in waters of the U.S,; and

- EPA community right to know regulations under the Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations.

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, OPA and analogous state laws and regulations, impose strict joint and several liability for costs required to clean up and restore sites where hazardous substances or other waste products have been disposed of or otherwise released. More stringent laws and regulations, including any related to climate change and greenhouse gases, may be adopted in the future. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other waste products into the environment.

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

Our oil and natural gas exploration, production and transportation operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. Failure or delay in obtaining regulatory approvals or drilling permits could have a material adverse effect on our ability to develop our properties, and receipt of drilling permits with onerous conditions could increase our compliance costs. In addition, regulations regarding conservation practices and the protection of correlative rights affect our operations by limiting the quantity of oil and natural gas we may produce and sell.

We are subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration, production and transportation of oil and natural gas. While the cost of compliance with these laws has not been material to our operations in the past, the possibility exists that new laws, regulations or enforcement policies could be more stringent and significantly increase our compliance costs. If we are not able to recover the resulting costs through insurance or increased revenues, our ability to pay distributions to our unitholders could be adversely affected.

Climate change legislation or regulations restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil and natural gas we produce.

On October 30, 2009, the EPA published a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the United States beginning in 2011 for emissions occurring in 2010. On November 30, 2010, the EPA published its amendments to the GHG reporting rule to include onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities, which may include facilities we operate. Reporting of GHG emissions from such facilities will be required on an annual basis beginning in 2012 for emissions occurring in 2011.

On December 15, 2009, the EPA officially published its findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the federal CAA. On January 2, 2011, the EPA’s GHG emission standards for light–duty vehicles became effective. This triggers the requirement that permits issued under the CAA Title V and Prevention of Significant Deterioration programs must address GHGs. In June 2010, EPA finalized a GHG tailoring rule, applying GHG permitting initially to the largest stationary sources of GHGs above certain revised emission limits.

In addition, both houses of Congress have considered legislation to reduce emissions of GHGs and many states have adopted or considered measures to reduce GHG emission reduction levels, often involving the planned development of GHG emission inventories and/or cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions or major producers of fuels to acquire and surrender emission allowances. The adoption and implementation of any legislation or regulatory programs imposing reporting obligations on, or limiting 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. Federal efforts at a cap and trade program appear to not be moving forward in Congress. Some members of Congress have publicly indicated an intention to introduce legislation to curb EPA's regulatory authority over GHGs.

Significant physical effects of climatic change have the potential to damage our facilities, disrupt our production activities and cause us to incur significant costs in preparing for or responding to those effects.

In an interpretative guidance on climate change disclosures, the SEC indicates that climate change could have an effect on the severity of weather (including hurricanes and floods), sea levels, the arability of farmland, and water availability and quality. If such effects were to occur, our exploration and production operations have the potential to be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low lying areas, disruption of our production activities either because of climate related damages to our facilities in our costs of operation potentially arising from such climatic effects, less efficient or non routine operating practices necessitated by climate effects or increased costs for insurance coverages in the aftermath of such effects. Significant physical effects of climate change could also have an indirect affect on our financing and operations by disrupting the transportation or process related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change.

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

Hydraulic fracturing is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and natural gas commissions but is not subject to regulation at the federal level. Nonetheless, 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 introduced in the recently completed session of Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process, and similar legislation could be introduced in the current session of Congress that convened on January 3, 2011. Also, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. For example, New York has imposed a de facto moratorium on the issuance of permits for high volume, horizontal hydraulic fracturing until state administered environmental studies are finalized, a draft of which must be published by June 1, 2011, followed by a 30 day comment period. Further, Pennsylvania has adopted a variety of regulations limiting how and where fracturing can be performed. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could make it more difficult or costly for us to perform hydraulic fracturing activities and thereby affect the determination of whether a well is commercially viable. In addition, if hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permit requirements or operational restrictions and also to associated permitting delays and potential increases in costs. Such federal or state legislation could require the disclosure of chemical constituents used in the fracturing process to state or federal regulatory authorities who could then make such information publicly available. For example, Wyoming has enacted regulations relating to the disclosure of chemical constituents in fracturing fluids. In addition, restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that we are ultimately able to produce in commercial quantities.

Changes in interest rates could adversely impact our unit price and our ability to issue additional equity and incur debt.

Interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. As with other yield oriented securities, our unit price is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank related yield oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue additional equity to make acquisitions, incur debt or for other purposes.

We may encounter obstacles to marketing our oil and natural gas, which could adversely impact our revenues.

The marketability of our production will depend in part upon the availability and capacity of natural gas gathering systems, pipelines and other transportation facilities owned by third parties. Transportation space on the gathering systems and pipelines we utilize is occasionally limited or unavailable due to repairs or improvements to facilities or due to space being utilized by other companies that have priority transportation agreements. Our access to transportation options can also be affected by U.S. federal and state regulation of oil and natural gas production and transportation, general economic conditions and changes in supply and demand. The availability of markets are beyond our control. If market factors dramatically change, the impact on our revenues could be substantial and could adversely affect our ability to produce and market oil and natural gas, the value of our units and our ability to pay distributions on our units.

We may experience a temporary decline in revenues and production if we lose one of our significant customers.

To the extent any significant customer reduces the volume of its oil or natural gas purchases from us, we could experience a temporary interruption in sales of, or a lower price for, our oil and natural gas production and our revenues and cash available for distribution could decline which could adversely affect our ability to make cash distributions to our unitholders.

Our ability to make cash distributions will depend on our ability to successfully drill and complete wells on our properties. Seasonal weather conditions and lease stipulations may adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Drilling operations in the Appalachian Basin, the San Juan Basin and Michigan are adversely affected by seasonal weather conditions, primarily in the spring. Many municipalities in Appalachia impose weight restrictions on the paved roads that lead to our jobsites due to the muddy conditions caused by spring thaws. In addition, our Monroe Field properties in Louisiana are subject to flooding. This limits our access to these jobsites and our ability to service wells in these areas on a year around basis.

The amount of cash we have available for distribution to holders of our common units depends on our cash flows.

The amount of cash that we have available for distribution depends primarily upon our cash flows, including financial reserves and cash flows from working capital borrowing, and not solely on profitability, which will be affected by non cash items. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes and may not make cash distributions during periods when we record net income for financial accounting purposes.

We have significant indebtedness under our credit facility. Restrictions in our credit facility may limit our ability to make distributions to you and may limit our ability to capitalize on acquisitions and other business opportunities.

Our credit facility contains covenants limiting our ability to make distributions, incur indebtedness, grant liens, make acquisitions, investments or dispositions and engage in transactions with affiliates, as well as containing covenants requiring us to maintain certain financial ratios and tests. In addition, the borrowing base under our facility is subject to periodic review by our lenders. Difficulties in the credit markets may cause the banks to be more restrictive when redetermining our borrowing base.

We may incur substantial debt in the future to enable us to maintain or increase our production levels and to otherwise pursue our business plan. This debt may restrict our ability to make distributions.

Our business requires a significant amount of capital expenditures to maintain and grow production levels. If prices were to decline for an extended period of time, if the costs of our acquisition and development operations were to increase substantially, or if other events were to occur which reduced our revenues or increased our costs, we may be required to borrow significant amounts in the future to enable us to finance the expenditures necessary to replace the reserves we produce. The cost of the borrowings and our obligations to repay the borrowings will reduce amounts otherwise available for distributions to our unitholders.

Risks Inherent in an Investment in Us

Sales of our common units by the selling unitholders may cause our unit price to decline.

Sales of substantial amounts of our common units in the public market, or the perception that these sales may occur, could cause the market price of our common units to decline. In addition, the sale of these units could impair our ability to raise capital through the sale of additional common units.

EnerVest controls our general partner, which has sole responsibility for conducting our business and managing our operations. EnerVest, EV Investors, L.P. ("EV Investors") and EnCap Investments, L.P. ("EnCap"), which are limited partners of our general partner, will have conflicts of interest, which may permit them to favor their own interests to your detriment.

EnerVest owns and controls our general partner and EnCap owns a 23.75% limited partnership interest in our general partner. Conflicts of interest may arise between EnerVest, EnCap and their respective affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its owners over the interests of our unitholders. These conflicts include, among others, the following situations:

- we have acquired oil and natural gas properties from partnerships formed by EnerVest and partnerships and companies in which EnerVest and EnCap have an interest, and we may do so in the future;

- neither our partnership agreement nor any other agreement requires EnerVest or EnCap to pursue a business strategy that favors us or to refer any business opportunity to us;

- our general partner is allowed to take into account the interests of parties other than us, such as EnerVest and EnCap, in resolving conflicts of interest;

- our general partner determines the amount and timing of our drilling program and related capital expenditures, asset purchases and sales, borrowings, issuance of additional partnership securities and reserves, each of which can affect the amount of cash that is distributed to unitholders;

- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;

- our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates; and

- our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

Many of the directors and officers who have responsibility for our management have significant duties with, and will spend significant time serving, entities that compete with us in seeking out acquisitions and business opportunities and, accordingly, may have conflicts of interest in allocating time or pursuing business opportunities.

In order to maintain and increase our levels of production, we will need to acquire oil and natural gas properties. Several of the officers and directors of EV Management, the general partner of our general partner, who have responsibilities for managing our operations and activities hold similar positions with other entities that are in the business of identifying and acquiring oil and natural gas properties. For example, Mr. Walker is Chairman and Chief Executive Officer of EV Management and President and Chief Executive Officer of EnerVest, which is in the business of acquiring oil and natural gas properties and managing the EnerVest partnerships that are in that business. Mr. Houser, President and Chief Operating Officer and a director of EV Management, is also Executive Vice President and Chief Operating Officer of EnerVest. We cannot assure you that these conflicts will be resolved in our favor. Mr. Gary R. Petersen, a director of EV Management, is also a senior managing director of EnCap, which is in the business of investing in oil and natural gas companies with independent management which in turn is in the business of acquiring oil and natural gas properties. Mr. Petersen is also a director of several oil and natural gas producing entities that are in the business of acquiring oil and natural gas properties. The existing positions of these directors and officers may give rise to fiduciary obligations that are in conflict with fiduciary obligation owed to us. The EV Management officers and directors may become aware of business opportunities that may be appropriate for presentation to us as well as the other entities with which they are or may be affiliated. Due to these existing and potential future affiliations with these and other entities, they may have fiduciary obligations to present potential business opportunities to those entities prior to presenting them to us, which could cause additional conflicts of interest. They may also decide that the opportunities are more appropriate for other entities which they serve and elect not to present them to us.

Neither EnerVest nor EnCap is limited in its ability to compete with us for acquisition or drilling opportunities. This could cause conflicts of interest and limit our ability to acquire additional assets or businesses which in turn could adversely affect our ability to replace reserves, results of operations and cash available for distribution to our unitholders.

Neither our partnership agreement nor the omnibus agreement between EnerVest and us prohibits EnerVest, EnCap and their affiliates from owning assets or engaging in businesses that compete directly or indirectly with us. For instance, EnerVest, EnCap and their respective affiliates may acquire, develop or dispose of additional oil or natural gas properties or other assets in the future, without any obligation to offer us the opportunity to purchase or develop any of those assets. Each of these entities is a large, established participant in the energy business, and each has significantly greater resources and experience than we have, which factors may make it more difficult for us to compete with these entities with respect to commercial activities as well as for acquisition candidates. As a result, competition from these entities could adversely impact our results of operations and accordingly cash available for distribution.

Cost reimbursements due to our general partner and its affiliates for services provided may be substantial and will reduce our cash available for distribution to our unitholders.

Pursuant to the omnibus agreement between EnerVest and us, EnerVest will receive reimbursement for the provision of various general and administrative services for our benefit. In addition, we entered into contract operating agreements with a subsidiary of EnerVest pursuant to which the subsidiary will be the contract operator of all of the wells for which we have the right to appoint an operator. Payments for these services will be substantial and will reduce the amount of cash available for distribution to unitholders. In addition, under Delaware partnership law, our general partner has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our general partner. To the extent our general partner incurs obligations on our behalf, we are obligated to reimburse or indemnify it. If we are unable or unwilling to reimburse or indemnify our general partner, our general partner may take actions to cause us to make payments of these obligations and liabilities. Any such payments could reduce the amount of cash otherwise available for distribution to our unitholders.

Our partnership agreement limits our general partner's fiduciary duties to holders of our common units.

Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the directors and officers of EV Management, the general partner of our general partner, have a fiduciary duty to manage our general partner in a manner beneficial to its owners. Our partnership agreement contains provisions that reduce the standards to which our general partner and its affiliates would otherwise be held by state fiduciary duty laws. For example, our partnership agreement permits our general partner and its affiliates to make a number of decisions either in their individual capacities, as opposed to in its capacity as our general partner, or otherwise free of fiduciary duties to us and our unitholders. This entitles our general partner and its affiliates to consider only the interests and factors that they desire, and they have no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include:

- whether or not to exercise its right to reset the target distribution levels of its incentive distribution rights at higher levels and receive, in connection with this reset, a number of Class B units that are convertible at any time following the first anniversary of the issuance of these Class B units into common units;
- whether or not to exercise its limited call right;
- how to exercise its voting rights with respect to the units it owns;
- whether or not to exercise its registration rights; and
- whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.

Our partnership agreement restricts the remedies available to holders of our common units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions restricting the remedies available to unitholders for actions taken by our general partner or its affiliates that might otherwise constitute breaches of fiduciary duty. For example, our partnership agreement:

- provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith, meaning it believed the decision was in the best interests of our partnership;

- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the conflicts committee of the board of directors of the general partner of our general partner and not involving a vote of unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or must be “fair and reasonable” to us, as determined by our general partner in good faith and that, in determining whether a transaction or resolution is “fair and reasonable,” our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us; and

- provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal.

Our general partner may elect to cause us to issue Class B units to it in connection with a resetting of the target distribution levels related to our general partner’s incentive distribution rights without the approval of the conflicts committee or holders of our common units. This may result in lower distributions to holders of our common units in certain situations.

Our general partner has the right to reset the initial cash target distribution levels at higher levels based on the distribution at the time of the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution amount will be reset to an amount equal to the average cash distribution amount per common unit for the two fiscal quarters immediately preceding the reset election (such amount is referred to as the “reset minimum quarterly distribution”) and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution amount.

In connection with resetting these target distribution levels, our general partner will be entitled to receive a number of Class B units. The Class B units will be entitled to the same cash distributions per unit as our common units and will be convertible into an equal number of common units. The number of Class B units to be issued will be equal to that number of common units whose aggregate quarterly cash distributions equaled the average of the distributions to our general partner on the incentive distribution rights in the prior two quarters. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion; however, it is possible that our general partner could exercise this reset election at a time when it is experiencing, or may be expected to experience, declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be issued our Class B units, which are entitled to receive cash distributions from us on the same priority as our common units, rather than retain the right to receive incentive distributions based on the initial target distribution levels. As a result, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued new Class B units to our general partner in connection with resetting the target distribution levels related to our general partner’s incentive distribution rights.

Holders of our common units have limited voting rights and are not entitled to elect our general partner or the board of directors of its general partner.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management’s decisions regarding our business. Unitholders will not elect our general partner, its general partner or the members of its board of directors, and will have no right to elect our general partner, its general partner or its board of directors on an annual or other continuing basis. The board of directors of EV Management is chosen by EnerVest, the sole member of EV Management. Furthermore, if the unitholders were dissatisfied with the performance of our general partner, they will have only a limited ability to remove our general partner. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Even if holders of our common units are dissatisfied, they will have difficulty removing our general partner without its consent.

The vote of the holders of at least 66 2/3% of all outstanding units voting together as a single class is required to remove the general partner. EnerVest owns and controls our general partner, and as of February 18, 2011, officers and directors of EV Management owned 5.5% of our aggregate outstanding common units. Accordingly, it may be difficult for holders of our common units to remove our general partner.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Unitholders' voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter. Our partnership 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 the unitholders' ability to influence the manner or direction of management.

Control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of the owners of our general partner or EV Management, from transferring all or a portion of their respective ownership interest in our general partner or EV Management to a third party. The new owners of our general partner or EV Management would then be in a position to replace the board of directors and officers of EV Management with its own choices and thereby influence the decisions taken by the board of directors and officers.

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

Our partnership agreement does not limit the number of additional limited partner interests that we may issue at any time without the approval of our unitholders. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

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

We have the right to borrow to make distributions. Repayment of these borrowings will decrease cash available for future distributions, and covenants in our credit facility may restrict our ability to make distributions.

Our partnership agreement allows us to borrow to make distributions. We may make short term borrowings under our credit facility, which we refer to as working capital borrowings, to make distributions. The primary purpose of these borrowings would be to mitigate the effects of short term fluctuations in our working capital that would otherwise cause volatility in our quarter to quarter distributions.

The terms of our credit facility may restrict our ability to pay distributions if we do not satisfy the financial and other covenants in the facility.

Our partnership agreement requires that we distribute all of our available cash, which could limit our ability to grow our reserves and production.

Our partnership agreement provides that we will distribute all of our available cash each quarter. As a result, we will be dependent on the issuance of additional common units and other partnership securities and borrowings to finance our growth. A number of factors will affect our ability to issue securities and borrow money to finance growth, as well as the costs of such financings, including:

- general economic and market conditions, including interest rates, prevailing at the time we desire to issue securities or borrow funds;
- conditions in the oil and natural gas industry;
- our results of operations and financial condition; and
- prices for oil and natural gas.

Our general partner has a limited call right that may require you to sell your units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80% of our common units, our general partner will have 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 common units held by unaffiliated persons at a price not less than their then current market price. As a result, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your units.

Your liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. You could be liable for any and all of our obligations as if you were a general partner if:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state's partnership statute; or
- your right to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitutes "control" of our business.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17–607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to you 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 the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable for the obligations of the assignor to make contributions to the partnership that are known to the substituted limited partner at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement. Liabilities to partners on account of their partnership interest and liabilities that are non–recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

If we distribute cash from capital surplus, which is analogous of a return of capital, our minimum quarterly distribution rate will be reduced proportionately, and the distribution thresholds after which the incentive distribution rights entitle our general partner to an increased percentage of distributions will be proportionately decreased.

Our cash distribution will be characterized as coming from either operating surplus or capital surplus. Operating surplus generally means amounts we receive from operating sources, such as sales of our oil and natural gas production, less operating expenditures, such as production costs and taxes, and less estimated maintenance capital, which are generally amounts we estimate we will need to spend in the future to maintain our production levels over the long term. Capital surplus generally means amounts we receive from non–operating sources, such as sales of properties and issuances of debt and equity securities. Cash representing capital surplus, therefore, is analogous to a return of capital. Distributions of capital surplus are made to our unitholders and our general partner in proportion to their percentage interests in us, or 98 percent to our unitholders and two percent to our general partner, and will result in a decrease in our minimum quarterly distribution and a lower threshold for distributions on the incentive distribution rights held by our general partner.

Our partnership agreement allows us to add to operating surplus up to two times the amount of our most recent minimum quarterly distribution. As a result, a portion of this amount, which is analogous to a return of capital, may be distributed to the general partner and its affiliates, as holders of incentive distribution rights, rather than to holders of common units as a return of capital.

If we fail to maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential unitholders could lose confidence in our financial reporting, which would harm our business and the trading price of our units.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to continue to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our units.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes and not being subject to a material amount of entity–level taxation by individual states. If the Internal Revenue Service treats us as a corporation or we become subject to a material amount of entity-level taxation for state tax purposes, it would reduce the amount of cash available for distribution to our unitholders.

The anticipated after–tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for U.S. federal income tax purposes. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service, which we refer to as the IRS, on this or any other tax matter affecting us.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income tax at varying rates. Distributions to you would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to you would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flows and after–tax return to the unitholders, likely causing a substantial reduction in the value of our common units.

Current law may change so as to cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to entity–level taxation. In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity–level taxation through the imposition of state income, franchise and other forms of taxation. For example, in Texas, we are now subject to an entity level tax on the portion of our income that is generated in Texas. Imposition of such a tax on us by Texas, or any other state, will reduce the cash available for distribution to a unitholder.

The partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution levels will be adjusted to reflect the impact of that law on us.

An IRS contest of our U.S. federal income tax positions may adversely affect the market for our common units, and the cost of any IRS contest will reduce our cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes or any other matter affecting us. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take. A court may not agree with all of our counsel's conclusions or positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, costs incurred in any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

You may be required to pay taxes on income from us even if you 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, you will be required to pay any federal income taxes and, in some cases, state and local income taxes on your share of our taxable income even if you receive no cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the tax liability that results from that income.

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

If you sell your common units, you will recognize a gain or loss equal to the difference between the amount realized and your tax basis in those common units. Prior distributions to you in excess of the total net taxable income you were allocated for a common unit, which decreased your tax basis in that common unit, will, in effect, become taxable income to you if the common unit is sold at a price greater than your tax basis in that common unit, even if the price is less than your original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income. In addition, if you sell your units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

Tax–exempt entities and foreign persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investment in common units by tax–exempt entities, such as individual retirement accounts (known as IRAs), other retirement plans and non–U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non–U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non–U.S. persons will be required to file U.S.federal tax returns and pay tax on their share of our taxable income.

We will treat each purchaser of our common units as having the same tax benefits without regard to the actual common 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 take depreciation and amortization positions that may not conform to all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns.

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 U.S. federal income tax purposes.

We will be considered to have terminated our partnership for U.S. 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 example, an exchange of 50% of our capital and profits could occur if, in any twelve–month period, holders of our common units sell at least 50% of the interests in our capital and profits. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income.

Unitholders may be subject to state and local taxes and tax return filing requirements in states where they do not live as a result of investing in our common units.

In addition to federal income taxes, you will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property, even if you do not live in any of those jurisdictions. You will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, you may be subject to penalties for failure to comply with those requirements. We own assets and do business in the states of Texas, Louisiana, Oklahoma, Arkansas, New Mexico, Colorado, Kansas, Michigan, Ohio, West Virginia and Pennsylvania. Each of these states, other than Texas, currently imposes a personal income tax. As we make acquisitions or expand our business, we may own assets or do business in additional states that impose a personal income tax. It is your responsibility to file all U.S. federal, foreign, state and local tax returns.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Information regarding our properties is contained in Item 1. Business "—Our Areas of Operation" and "—Our Oil and Natural Gas Data" and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations ""—Results of Operations" contained herein.

ITEM 3. LEGAL PROCEEDINGS

We are involved in disputes or legal actions arising in the ordinary course of business. We do not believe the outcome of such disputes or legal actions will have a material adverse effect on our consolidated financial statements, and no amounts have been accrued at December 31, 2010.

ITEM 4. (REMOVED AND RESERVED)

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED UNITHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common units are traded on the NASDAQ Global Market under the symbol "EVEP." At the close of business on February 18, 2011, based upon information received from our transfer agent and brokers and nominees, we had 141 common unitholders of record. This number does not include owners for whom common units may be held in "street" names.

The following table sets forth the range of the daily high and low sales prices per common unit and cash distributions to common unitholders for 2010 and 2009:

	Price Range		Cash Distribution per
	High	**Low**	**Common Unit [1]**
2010:			
First Quarter	$ 32.93	$ 27.24	$ 0.756
Second Quarter	34.95	21.24	0.757
Third Quarter	37.90	30.01	0.758
Fourth Quarter	40.24	35.04	0.759 [2]
2009:			
First Quarter	$ 19.66	$ 12.50	$ 0.752
Second Quarter	23.30	14.01	0.753
Third Quarter	24.79	17.57	0.754
Fourth Quarter	31.70	22.90	0.755

(1) Cash distributions are declared and paid in the following calendar quarter.

(2) On January 26, 2011, the board of directors of EV Management declared a quarterly cash distribution for the fourth quarter of 2010 of $0.759 per unit. The distribution was paid on February 14, 2011.

Cash Distributions to Unitholders

We intend to continue to make cash distributions to unitholders on a quarterly basis, although there is no assurance as to the future cash distributions since they are dependent upon future earnings, cash flows, capital requirements, financial condition and other factors. Our credit agreement prohibits us from making cash distributions if any potential default or event of default, as defined in the credit agreement, occurs or would result from the cash distribution.

Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash (as defined in our partnership agreement) to unitholders of record on the applicable record date. The amount of available cash generally is all cash on hand at the end of the quarter:

- *less* the amount of cash reserves established by our general partner to:
  - provide for the proper conduct of our business;
  - comply with applicable law, any of our debt instruments or other agreements; or
  - provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters;
- *plus*, if our general partner so determines, all or a portion of cash on hand on the date of determination of available cash for the quarter including cash from working capital borrowings.

Working capital borrowings are borrowings used solely for working capital purposes or to pay distributions to unitholders.

Initially, our general partner was entitled to 2% of all quarterly distributions that we made prior to our liquidation. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. The general partner's initial 2% interest in these distributions will be reduced if we issue additional units in the future and our general partner does not contribute a proportionate share of capital to us to maintain its 2% general partnership interest. When we issued common units in 2009 and 2010, our general partner contributed to us an amount of cash necessary to maintain its 2% interest.

Our general partner also holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 25%, of the cash we distribute from operating surplus (as defined in our partnership agreement) in excess of $0.46 per unit per quarter. The maximum distribution percentage of 25% includes distributions paid to our general partner on its 2% general partner interest and assumes that our general partner maintains its general partner interest at 2%. The maximum distribution percentage of 25% does not include any distributions that our general partner may receive on common units that it owns. For additional information on our distributions, please see Note 10 of the Notes to Consolidated Financial Statements in Item 8. "Financial Statements and Supplementary Data."

Our partnership agreement requires that we make distributions of available cash from operating surplus for any quarter in the following manner:

- *first*, 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding common unit an amount equal to the minimum quarterly distribution for that quarter; and

- *thereafter*, cash in excess of the minimum quarterly distributions is distributed to the unitholders and the general partner based on the percentages below.

Our general partner is entitled to incentive distributions if the amount we distribute with respect to one quarter exceeds specified target levels shown below:

		Marginal Percentage Interest in Distributions	
	Total Quarterly Distributions Target Amount	**Limited Partner**	**General Partner**
Minimum quarterly distribution	$0.40	98%	2%
First target distribution	Up to $0.46	98%	2%
Second target distribution	Above $0.46, up to $0.50	85%	15%
Thereafter	Above $0.50	75%	25%

Unregistered Sales of Equity Securities

None.

Issuer Purchases of Equity Securities

None.

ITEM 6. SELECTED FINANCIAL DATA

The following table shows selected financial data of us and our predecessors for the periods and as of the dates indicated. The selected financial data for the years ended December 31, 2010, 2009, 2008 and 2007 and three months ended and as of December 31, 2006 are derived from our audited financial statements. The selected financial data for the nine months ended and as of September 30, 2006 is derived from the audited financial statements of our predecessors. The selected financial data should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data," both contained herein.

	Successor					Predecessors [(1)]
	Year Ended December 31,				Three Months Ended December 31,	Nine Months Ended September 30,
	2010 [(2)]	2009 [(3)]	2008 [(4)]	2007 [(5)]	2006 [(6)]	2006
Statement of Operations Data:						
Revenues:						
Oil, natural gas and natural gas liquids revenues	$ 165,738	$ 114,066	$ 192,757	$ 89,422	$ 5,548	$ 34,379
Gain on derivatives, net [(7)]	–	–	1,597	3,171	999	1,254
Transportation and marketing–related revenues	5,780	7,846	12,959	11,415	1,271	4,458
Total revenues	171,518	121,912	207,313	104,008	7,818	40,091
Operating costs and expenses:						
Lease operating expenses	53,736	41,495	42,681	21,515	1,493	6,085
Cost of purchased natural gas	4,353	4,509	9,849	9,830	1,153	3,860
Production taxes	7,867	5,983	9,088	3,360	109	185
Dry hole and exploration costs	417	–	–	–	–	1,415
Impairment of unproved oil and natural gas properties	–	–	–	–	–	90
Asset retirement obligations accretion expense	3,153	2,035	1,434	814	89	129
Depreciation, depletion and amortization	55,221	52,048	38,032	19,759	1,180	4,388
General and administrative expenses	23,313	18,556	13,653	10,384	2,043	1,491
Gain on sales of oil and natural gas properties	(40,656)	–	–	–	–	–
Total operating costs and expenses	107,404	124,626	114,737	65,662	6,067	17,643
Operating income (loss)	64,114	(2,714)	92,576	38,346	1,751	22,448
Other income (expense), net	42,222	4,372	133,144	(27,102)	1,616	(229)
Income before income taxes and equity in income of affiliates	106,336	1,658	225,720	11,244	3,367	22,219
Income taxes	(285)	(248)	(235)	(54)	–	(5,809)
Equity in income of affiliates	–	–	–	–	–	164
Net income	$ 106,051	$ 1,410	$ 225,485	$ 11,190	$ 3,367	$ 16,574
General partner's interest in net income, including incentive distribution rights	$ 11,938	$ 7,040	$ 8,847	$ 1,221	$ 67	
Limited partners' interest in net income (loss)	$ 94,113	$ (5,630)	$ 216,638	$ 9,969	$ 3,300	
Net income (loss) per limited partner unit:						
Basic	$ 3.35	$ (0.29)	$ 14.12	$ 0.77	$ 0.43	
Diluted	$ 3.34	$ (0.29)	$ 14.12	$ 0.77	$ 0.43	
Distributions declared per unit	$ 3.03	$ 3.01	$ 2.82	$ 2.12	$ 0.40	
Financial Position (at end of period):						
Working capital	$ 84,765	$ 52,825	$ 94,817	$ 16,438	$ 12,006	$ 9,190
Total assets	1,486,757	907,705	979,995	607,541	132,689	95,749
Long–term debt	619,000	302,000	467,000	270,000	28,000	10,350
Owners' equity	773,947	547,431	457,484	283,030	96,253	63,240

(1) The financial statements of our predecessors were prepared on a combined basis as the entities were under common control.

(2) Includes the results of (i) the acquisition of oil and natural gas properties in the Appalachian Basin in March 2010 and June 2010, (ii) the acquisition of oil and natural gas properties in the Mid–Continent area in September 2010, (iii) the acquisition of oil and natural gas properties in the San Juan Basin in July 2010 and December 2010, (iii) the acquisition of oil and natural properties in Central and East Texas in October 2010 and (iv) the acquisition of oil and natural gas properties in the Barnett Shale in December 2010.

(3) Includes the results of (i) the acquisition of oil and natural gas properties in Central and East Texas in July 2009, (ii) the acquisition of oil and natural gas properties in Central and East Texas in September 2009 and (iii) the acquisition of oil and natural gas properties in the Appalachian Basin in November 2009.

(4) Includes the results of (i) the acquisition of oil properties in Central and East Texas in May 2008, (ii) the acquisitions of oil and natural gas properties in Michigan, Central and East Texas and the Mid–Continent area in August 2008, (iii) the acquisition of natural gas properties in West Virginia September 2008 and (iv) the acquisition of oil and natural gas properties in the San Juan Basin in September 2008.

(5) Includes the results of (i) the acquisition of natural gas properties in Michigan in January 2007, (ii) the acquisition of additional natural gas properties in the Monroe Field in March 2007, (iii) the acquisition of oil and natural gas properties in Central and East Texas in June 2007, (iv) the acquisition of oil and natural gas properties in the Permian Basin in October 2007 and (v) the acquisition of oil and natural gas properties in the Appalachian Basin in December 2007.

(6) Includes the results of the acquisition of oil and natural gas properties in the Mid–Continent area in December 2006.

(7) Our predecessors accounted for their derivatives as cash flow hedges. Accordingly, the changes in fair value of the derivatives were reported in accumulated other comprehensive income ("AOCI") and reclassified to net income in the periods in which the contracts were settled. As of October 1, 2006, we elected not to designate our derivatives as hedges. The amount in AOCI at that date related to derivatives that previously were designated and accounted for as cash flow hedges continued to be deferred until the underlying production was produced and sold, at which time amounts were reclassified from AOCI and reflected as a component of revenues. Changes in the fair value of derivatives that existed at October 1, 2006 and any derivatives entered into thereafter are no longer deferred in AOCI, but rather are recorded immediately to net income as "Unrealized gains (losses) on derivatives, net", which are included in "Other income (expense), net" in our consolidated statement of operations.

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

Management's Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with "Item 8. Financial Statements and Supplementary Data" contained herein.

OVERVIEW

We are a Delaware limited partnership formed in April 2006 by EnerVest to acquire, produce and develop oil and natural gas properties. Our general partner is EV Energy GP, a Delaware limited partnership, and the general partner of our general partner is EV Management, a Delaware limited liability company.

As of December 31, 2010, our properties were located in the Barnett Shale, the Appalachian Basin (primarily in Ohio and West Virginia), the Mid-Continent area in Oklahoma, Texas, Arkansas, Kansas and Louisiana, the San Juan Basin, the Monroe Field in Louisiana, the Permian Basin, Central and East Texas (which includes the Austin Chalk area), and Michigan. As of December 31, 2010, we had estimated net proved reserves of 12.9 MMBbls of oil, 27.5 MMBbls of natural gas liquids and 575.2 Bcf of natural gas, or 817.3 Bcfe, and a standardized measure of $1,020.2 million.

Developments in 2010

Acquisitions and Divestitures

In March 2010 followed by a second closing in June 2010, we, along with certain institutional partnerships managed by EnerVest, acquired oil and natural gas properties in the Appalachian Basin. We acquired a 46.15% proportional interest in these properties for $145.8 million.

In September 2010, we acquired oil and natural gas properties in the Mid–Continent area for $119.9 million, subject to customary closing conditions and purchase price adjustments.

In December, 2010, we, along with certain institutional partnerships managed by EnerVest, acquired oil and natural gas properties in the Barnett Shale, including certain related derivatives. We acquired a 31.02% proportional interest in these properties for $295.8 million, subject to customary closing conditions and purchase price adjustments.

In addition to the acquisitions described above, in 2010, we, along with institutional partnerships managed by EnerVest, also acquired oil and natural gas properties in the Appalachian Basin, the San Juan Basin and Central and East Texas for an aggregate purchase price of $7.0 million.

In 2010, we recorded a gain of $40.7 million primarily related to sales of unproved oil and natural gas properties.

Public Offerings

In February 2010, we closed a public offering of 3.45 million common units at an offering price of $28.08 per common unit. We received net proceeds of $94.6 million, including a contribution of $2.0 million by our general partner to maintain its 2% interest in us.

In August 2010, we closed a public offering of 3.45 million of our common units at an offering price of $33.97 per common unit. We received net proceeds of $114.3 million, including a contribution of $2.3 million by our general partner to maintain its 2% interest in us.

Business Environment

Our primary business objective is to provide stability and growth in cash distributions per unit over time. The amount of cash we can distribute on our units principally depends upon the amount of cash generated from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the prices at which we will sell our oil, natural gas liquids and natural gas production;
- our ability to hedge commodity prices;
- the amount of oil, natural gas liquids and natural gas we produce; and
- the level of our operating and administrative costs.

Oil and natural gas prices are expected to be volatile in the future. Factors affecting the price of oil include worldwide economic conditions, geopolitical activities, worldwide supply disruptions, weather conditions, actions taken by the Organization of Petroleum Exporting Countries and the value of the U.S. dollar in international currency markets. Factors affecting the price of natural gas include the discovery of substantial accumulations of natural gas in unconventional reservoirs due to technological advancements necessary to commercially produce these unconventional reserves, North American weather conditions, industrial and consumer demand for natural gas, storage levels of natural gas and the availability and accessibility of natural gas deposits in North America.

In order to mitigate the impact of changes in oil and natural gas prices on our cash flows, we are a party to derivatives, and we intend to enter into derivatives in the future to reduce the impact of oil and natural gas price volatility on our cash flows. By removing a significant portion of this price volatility on our future oil and natural gas production through August 2014, we have mitigated, but not eliminated, the potential effects of changing oil and natural gas prices on our cash flows from operations for those periods. If commodity prices are depressed for an extended period of time, it could alter our acquisition and development plans, and adversely affect our growth strategy and ability to access additional capital in the capital markets.

The primary factors affecting our production levels are capital availability, our ability to make accretive acquisitions, the success of our drilling program and our inventory of drilling prospects. In addition, as initial reservoir pressures are depleted, production from our wells decreases. We attempt to overcome this natural decline through a combination of drilling and acquisitions. Our future growth will depend on our ability to continue to add reserves through drilling and acquisitions in excess of production. We will maintain our focus on the costs to add reserves through drilling and acquisitions as well as the costs necessary to produce such reserves. Our ability to add reserves through drilling is dependent on our capital resources and can be limited by many factors, including our ability to timely obtain drilling permits and regulatory approvals. Any delays in drilling, completion or connection to gathering lines of our new wells will negatively impact our production, which may have an adverse effect on our revenues and, as a result, cash available for distribution.

We focus our efforts on increasing oil and natural gas reserves and production while controlling costs at a level that is appropriate for long–term operations. Our future cash flows from operations are dependent upon our ability to manage our overall cost structure.

Critical Accounting Policies

The discussion and analysis of our financial condition and results of operations is based upon the consolidated financial statements, which have been prepared in accordance with U.S. generally accepted accounting principles. The preparation of these consolidated financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosures about contingent assets and liabilities. Certain of our accounting policies involve estimates and assumptions 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 base these estimates and assumptions on historical experience and on various other information and 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. Estimates and assumptions about future events and their effects cannot be perceived with certainty and, accordingly, these estimates may change as additional information is obtained, as more experience is acquired, as our operating environment changes and as new events occur.

Our critical accounting policies are important to the portrayal of both our financial condition and results of operations and require us to make difficult, subjective or complex assumptions or estimates about matters that are uncertain. We would report different amounts in our consolidated financial statements, which could be material, if we used different assumptions or estimates. We believe that the following are the critical accounting policies used in the preparation of our consolidated financial statements.

Oil and Natural Gas Properties

We account for our oil and natural gas properties using the successful efforts method of accounting. Under this method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Oil and natural gas lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for oil and natural gas leases, are charged to expense during the period the costs are incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities.

No gains or losses are recognized upon the disposition of oil and natural gas properties except in transactions such as the significant disposition of an amortizable base that significantly affects the unit–of–production amortization rate. Sales proceeds are credited to the carrying value of the properties.

The application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as development or exploratory which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Wells may be completed that are assumed to be productive and actually deliver oil and natural gas in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. Wells are drilled that have targeted geologic structures that are both developmental and exploratory in nature, and an allocation of costs is required to properly account for the results. Delineation seismic incurred to select development locations within an oil and natural gas field is typically considered a development cost and capitalized, but often these seismic programs extend beyond the reserve area considered proved and management must estimate the portion of the seismic costs to expense. The evaluation of oil and natural gas leasehold acquisition costs requires managerial judgment to estimate the fair value of these costs with reference to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

The successful efforts method of accounting can have a significant impact on the operational results reported when we are entering a new exploratory area in hopes of finding an oil and natural gas field that will be the focus of future developmental drilling activity. The initial exploratory wells may be unsuccessful and will be expensed. Seismic costs can be substantial which will result in additional exploration expenses when incurred.

We assess our proved oil and natural gas properties for possible impairment whenever events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. Such events include a projection of future oil and natural gas reserves that will be produced from a field, the timing of this future production, future costs to produce the oil and natural gas and future inflation levels. If the carrying amount of a property exceeds the sum of the estimated undiscounted future net cash flows, we recognize an impairment expense equal to the difference between the carrying value and the fair value of the property, which is estimated to be the expected present value of the future net cash flows from proved reserves. Estimated future net cash flows are based on existing proved reserves, forecasted production and cost information and management's outlook of future commodity prices. The underlying commodity prices used in the determination of our estimated future net cash flows are based on NYMEX forward strip prices at the end of the period, adjusted by field or area for estimated location and quality differentials, as well as other trends and factors that management believes will impact realizable prices. Future operating costs estimates, including appropriate escalators, are also developed based on a review of actual costs by field or area. Downward revisions in estimates of reserve quantities or expectations of falling commodity prices or rising operating costs could result in a reduction in undiscounted future cash flows and could indicate a property impairment.

Estimates of Oil and Natural Gas Reserves

Our estimates of proved oil and natural gas reserves are based on the 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 – 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 estimate. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. For example, we must estimate the amount and timing of future operating costs, severance taxes, development costs and workover costs, all of which may vary considerably from actual results. In addition, as prices and cost levels change from year to year, the estimate of proved reserves also changes. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves. Independent reserve engineers prepare our reserve estimates at the end of each year.

Despite the inherent imprecision in these engineering estimates, our reserves are used throughout our financial statements. For example, since we use the units–of–production method to amortize the costs of our oil and natural gas properties, the quantity of reserves could significantly impact our depreciation, depletion and amortization expense. Our reserves are also the basis of our supplemental oil and natural gas disclosures.

Accounting for Derivatives

We use derivatives to hedge against the variability in cash flows associated with the forecasted sale of our anticipated future oil and natural gas production. We generally hedge a substantial, but varying, portion of our anticipated oil and natural gas production for the next 12 – 48 months. We do not use derivatives for trading purposes. We have elected not to apply hedge accounting to our derivatives. Accordingly, we carry our derivatives at fair value on our consolidated balance sheet, with the changes in the fair value included in our consolidated statement of operations in the period in which the change occurs. Our current results of operations would potentially have been significantly different had we elected and qualified for hedge accounting on our derivatives.

In determining the amounts to be recorded, we are required to estimate the fair values of the derivatives. We base our estimates of fair value upon various factors that include closing prices on the NYMEX, volatility, the time value of options and the credit worthiness of the counterparties to our derivative instruments. These pricing and discounting variables are sensitive to market volatility as well as changes in future price forecasts and interest rates.

Accounting for Asset Retirement Obligations

We have significant obligations to remove tangible equipment and facilities and restore land at the end of oil and natural gas production operations. Our removal and restoration obligations are primarily associated with site reclamation, dismantling facilities and plugging and abandoning wells. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

We record an asset retirement obligation ("ARO") and capitalize the asset retirement cost in oil and natural gas properties in the period in which the retirement obligation is incurred based upon the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon wells. After recording these amounts, the ARO is accreted to its future estimated value using an assumed cost of funds and the additional capitalized costs are depreciated on a unit–of–production basis.

Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions of these assumptions impact the present value of the existing asset retirement obligation, a corresponding adjustment is made to the oil and natural gas property balance.

Revenue Recognition

Oil, natural gas and natural gas liquids revenues are recognized when production is sold to a purchaser at fixed or determinable prices, when delivery has occurred and title has transferred and collectibility of the revenue is probable. 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 oil, natural gas and natural gas liquids and prevailing supply and demand conditions, so that prices fluctuate to remain competitive with other available suppliers.

There are two principal accounting practices to account for natural gas imbalances. These methods differ as to whether revenue is recognized based on the actual sale of natural gas (sales method) or an owner's entitled share of the current period's production (entitlement method). We follow the sales method of accounting for natural gas revenues. Under this method of accounting, revenues are recognized based on volumes sold, which may differ from the volume to which we are entitled based on our working interest. An imbalance is recognized as a liability only when the estimated remaining reserves will not be sufficient to enable the under–produced owner(s) to recoup its entitled share through future production. Under the sales method, no receivables are recorded where we have taken less than our share of production.

We own and operate a network of natural gas gathering systems in the Monroe Field in Northern Louisiana which gather and transport owned natural gas and a small amount of third party natural gas to intrastate, interstate and local distribution pipelines. Natural gas gathering and transportation revenue is recognized when the natural gas has been delivered to a custody transfer point.

RESULTS OF OPERATIONS

	Year Ended December 31,		
	2010	2009	2008
Production data:			
Oil (MBbls)	679	514	437
Natural gas liquids (MBbls)	728	768	543
Natural gas (MMcf)	19,486	16,519	14,578
Net production (MMcfe)	27,933	24,210	20,457
Average sales price per unit:			
Oil (Bbl)	$ 74.78	$ 56.17	$ 94.76
Natural gas liquids (Bbl)	42.64	31.08	54.75
Natural gas (Mcf)	4.30	3.71	8.34
Mcfe	5.93	4.71	9.42
Average unit cost per Mcfe:			
Production costs:			
Lease operating expenses	$ 1.92	$ 1.71	$ 2.09
Production taxes	0.28	0.25	0.44
Total	2.20	1.96	2.53
Asset retirement obligations accretion expense	0.11	0.08	0.07
Depreciation, depletion and amortization	1.98	2.15	1.86
General and administrative expenses	0.83	0.77	0.67

Year Ended December 31, 2010 Compared with the Year Ended December 31, 2009

Net income for 2010 was $106.1 million, an increase of $104.6 million compared with 2009. This increase was primarily the result of $49.6 million of higher revenues due to increased production and higher prices for oil, natural gas and natural gas liquids, $54.7 million related to non–cash changes in the fair value of our derivatives and a gain of $40.7 million on the sales of oil and natural gas properties, partially offset by $20.0 million of lower realized gains on our derivatives, $12.2 million of increased lease operating expenses and $4.8 million of increased general and administrative expenses.

Oil, natural gas and natural gas liquids revenues for 2010 totaled $165.7 million, an increase of $51.7 million compared with 2009. This increase was primarily the result of $28.2 million related to higher prices for oil, natural gas liquids and natural gas and $23.5 million related to increased production.

Transportation and marketing–related revenues for 2010 decreased $2.1 million compared with 2009 primarily due to the recognition of deferred revenues of $1.8 million in 2009 from the production curtailments in the Monroe Field in 2008.

Lease operating expenses for 2010 increased $12.2 million compared with 2009 primarily as the result of $6.9 million due to our expanded acquisition and development drilling program, $3.1 million due to generally higher service costs experienced in our industry and $2.3 million ($0.08 per Mcfe) associated with the sales of oil in tanks acquired in the March 2010 acquisition. Lease operating expenses per Mcfe were $1.92 in 2010 compared with $1.71 in 2009.

Production taxes for 2010, which are generally based on a percentage of our oil, natural gas and natural gas liquids revenues, increased $1.9 million compared with 2009 primarily as the result of $1.1 million due to increased production and $0.8 million due to higher prices for oil, natural gas and natural gas liquids. Production taxes for 2010 were $0.28 per Mcfe compared with $0.25 per Mcfe for 2009.

Asset retirement obligations accretion expense for 2010 increased $1.1 million compared with 2009 primarily due to the oil and natural gas properties that we acquired in 2009 and 2010. Asset retirement obligations accretion expense for 2010 was $0.11 per Mcfe compared with $0.08 per Mcfe for 2009.

Depreciation, depletion and amortization for 2010 increased $3.2 million compared with 2009 primarily due to $7.4 million from higher production offset by a decrease of $4.2 million due to a lower average DD&A rate per unit. The lower average DD&A rate reflects the effect of our acquisitions of oil and natural gas properties in 2010. Depreciation, depletion and amortization for 2010 was $1.98 per Mcfe compared with $2.15 per Mcfe for 2009.

General and administrative expenses for 2010 totaled $23.3 million, an increase of $4.8 million compared with 2009. This increase is primarily the result of (i) $2.5 million of higher compensation costs primarily related to our equity–based compensation, (ii) $1.1 million of higher fees paid to EnerVest under the omnibus agreement due to our acquisitions of oil and natural gas properties in 2010 and 2009 and (iii) $1.2 million of increased costs incurred in conjunction with the integration of the oil and natural gas properties acquired in 2010. General and administrative expenses were $0.83 per Mcfe for 2010 compared with $0.77 per Mcfe for 2009.

Gain on sales of oil and natural gas properties was $40.7 million for 2010 and was primarily related to the sale of unproved oil and natural gas properties.

Realized gains (losses) on derivatives, net represent the monthly settlements with our counterparties related to derivatives that matured during the period. During 2010 and 2009, we received cash payments of $49.0 million and $69.0 million, respectively, from our counterparties as the contract prices for our derivatives exceeded the underlying market price for that period.

Unrealized gains (losses) on derivatives, net represent the change in the fair value of our open derivatives during the period. In 2010, the fair value of our open derivatives increased from a net asset of $93.1 million at December 31, 2009 to a net asset of $103.9 million at December 31, 2010, after giving effect to the $7.8 million of derivatives acquired in December 2010. In 2009, the fair value of our open derivatives decreased from a net asset of $144.7 million at December 31, 2008 to a net asset of $93.1 million at December 31, 2009.

Interest expense for 2010 decreased $1.9 million compared with 2009 primarily due to a decrease of $2.6 million from lower weighted average borrowings outstanding under our credit facility offset by an increase of $0.7 million due to a higher weighted average effective interest rate in 2010 compared with 2009.

Year Ended December 31, 2009 Compared with the Year Ended December 31, 2008

Net income for 2009 was $1.4 million, a decrease of $224.1 million compared with 2008. Of this decrease, $216.5 million related to non–cash changes in the value of our derivatives. We have entered into oil and natural gas derivatives to hedge significant amounts of our anticipated oil and natural gas production through August 2014, and we carry these derivatives at fair value on our consolidated balance sheet. The changes in the fair value of these derivatives are included in our consolidated statement of operations in the period in which the change occurs, and the unrealized gains and losses on these derivatives can fluctuate significantly from period to period as prices for oil and natural gas change. The remainder of the decrease was primarily related to (i) lower revenues due to decreased prices for oil, natural gas and natural gas liquids, (ii) higher depreciation, depletion and amortization expense, and (iii) increased general and administrative expenses as a result of our continued growth partially offset by lower lease operating expenses and production taxes.

Oil, natural gas and natural gas liquids revenues for 2009 totaled $114.1 million, a decrease of $78.7 million compared with 2008. This decrease was primarily the result of a decrease of $93.7 million related to lower prices for oil, natural gas liquids and natural gas partially offset by an increase of $14.4 million related to the oil and natural gas properties that we acquired in 2009 and 2008 and an increase of $0.6 million related to increased production at oil and natural gas properties that we acquired prior to 2008.

Transportation and marketing–related revenues for 2009 decreased $5.1 million compared with 2008 primarily due to a decrease of $5.7 million related to lower prices in 2009 compared with 2008 for the natural gas that we transport through our gathering systems in the Monroe Field offset by an increase of $0.6 million related to the recognition of deferred revenues from the production curtailments in the Monroe Field in 2008.

Lease operating expenses for 2009 decreased $1.2 million compared with 2008 primarily as the result of a decrease of $6.9 million related to the oil and natural gas properties that we acquired prior to 2008 offset by an increase of $5.7 million of lease operating expenses associated with the oil and natural gas properties that we acquired in 2009 and 2008. Lease operating expenses per Mcfe were $1.71 in 2009 compared with $2.09 in 2008. This decrease reflects a downward trend in operating costs in 2009 throughout the oil and natural gas industry.

The cost of purchased natural gas for 2009 decreased $5.3 million compared with 2008 primarily due to lower prices for natural gas that we purchased and transported through our gathering systems in the Monroe Field.

Production taxes for 2009 decreased $3.1 million compared with 2008 primarily as the result of a decrease of $4.4 million in production taxes associated with our decreased oil, natural gas and natural gas liquids revenues offset by an increase of $1.3 million in production taxes associated with the oil and natural gas properties that we acquired in 2009 and 2008. Production taxes for 2009 were $0.25 per Mcfe compared with $0.44 per Mcfe for 2008.

Asset retirement obligations accretion expense for 2009 increased $0.6 million compared with 2008 primarily due to $0.3 million related to the oil and natural gas properties that we acquired in 2009 and 2008 and $0.3 million from the drilling of new wells on the oil and natural gas properties that we acquired prior to 2008. Asset retirement obligations accretion expense for 2009 was $0.08 per Mcfe compared with $0.07 per Mcfe for 2008.

Depreciation, depletion and amortization for 2009 increased $14.0 million compared with 2008 primarily due to $7.4 million related to the oil and natural gas properties that we acquired in 2009 and 2008 and $6.5 million related to the oil and natural gas properties that we acquired prior to 2008. This increase is mainly attributable to a higher depreciation, depletion and amortization rate for the properties acquired during the second half of 2008. Depreciation, depletion and amortization for 2009 was $2.15 per Mcfe compared with $1.86 per Mcfe for 2008.

General and administrative expenses include the costs of administrative employees and related benefits, management fees paid to EnerVest, professional fees and other costs not directly associated with field operations. General and administrative expenses for 2009 totaled $18.6 million, an increase of $4.9 million compared with 2008. This increase is primarily the result of an increase of $2.1 million of fees paid to EnerVest under the omnibus agreement due to our acquisitions of oil and natural gas properties in 2008 and 2009 and an increase of $2.8 million in compensation costs related to our phantom units and performance units. General and administrative expenses were $0.77 per Mcfe in 2009 compared with $0.67 per Mcfe in 2008.

Realized gains (losses) on derivatives, net represent the monthly settlements with our counterparties related to derivatives that matured during the period. During 2009, we received cash payments of $69.0 million from our counterparties as the contract prices for our derivatives exceeded the underlying market prices for that period. During 2008, we made cash payments of $14.6 million to our counterparties as the contract prices for our derivatives were lower than the underlying market prices for that period.

Unrealized gains (losses) on derivatives, net represent the change in the fair value of our open derivatives during the period. In 2009, the fair value of our open derivatives decreased from a net asset of $144.7 million at December 31, 2008 to a net asset of $93.1 million at December 31, 2009. In 2008, the fair value of our open derivatives increased from a net liability of $18.5 million at December 31, 2007 to a net asset of $144.7 million at December 31, 2008.

Interest expense for 2009 decreased $3.8 million compared with 2008 primarily due to $1.4 million of additional interest expense from the increase in weighted average borrowings outstanding under our credit facility offset by $5.1 million due to a lower weighted average effective interest rate in 2009 compared with 2008.

LIQUIDITY AND CAPITAL RESOURCES

Historically, our primary sources of liquidity and capital have been issuances of equity securities, borrowings under our credit facility and cash flows from operations, and our primary uses of cash have been acquisitions of oil and natural gas properties and related assets, development of our oil and natural gas properties, distributions to our partners and working capital needs. For 2011, we believe that cash on hand and net cash flows generated from operations will be adequate to fund our capital budget and satisfy our short–term liquidity needs. We may also utilize various financing sources available to us, including the issuance of equity or debt securities through public offerings or private placements, to fund our acquisitions and long–term liquidity needs. Our ability to complete future offerings of equity or debt securities and the timing of these offerings will depend upon various factors including prevailing market conditions and our financial condition.

In the past we accessed the equity markets to finance our significant acquisitions. While we have been successful in accessing the public equity markets in 2010, any disruptions in the financial markets may limit our ability to access the public equity or debt markets in the future.

Available Credit Facility

We have a $700.0 million facility that expires in October 2012. Borrowings under the facility are secured by a first priority lien on substantially all of our assets and the assets of our subsidiaries. We may use borrowings under the facility for acquiring and developing oil and natural gas properties, for working capital purposes, for general corporate purposes and for funding distributions to partners. We also may use up to $50.0 million of available borrowing capacity for letters of credit. The facility requires the maintenance of a current ratio (as defined in the facility) of greater than 1.0 and a ratio of total debt to earnings plus interest expense, taxes, depreciation, depletion and amortization expense and exploration expense of no greater than 4.0 to 1.0. As of December 31, 2010, we were in compliance with all of the facility's financial covenants.

Borrowings under the facility may not exceed a "borrowing base" determined by the lenders based on our oil and natural gas reserves. As of December 31, 2010, the borrowing base was $700.0 million. The borrowing base is subject to scheduled redeterminations as of April 1 and October 1 of each year with an additional redetermination once per calendar year at our request or at the request of the lenders and with one calculation that may be made at our request during each calendar year in connection with material acquisitions or divestitures of properties. The borrowing base is determined by each lender based on the value of our proved oil and natural gas reserves using assumptions regarding future prices, costs and other matters that may vary by lender.

The facility also provides that if we issue senior debt between scheduled redetermination dates other than in conjunction with an interim redetermination, the borrowing base then in effect on the date on which such senior debt is issued will be reduced by an amount equal to the product of 0.30 multiplied by the stated principal amount of such senior debt.

Borrowings under the facility will bear interest at a floating rate based on, at our election, a base rate or the London Inter–Bank Offered Rate plus applicable premiums based on the percent of the borrowing base that we have outstanding.

At December 31, 2010, we had $619.0 million outstanding under the facility.

Cash and Short–term Investments

At December 31, 2010, we had $23.1 million of cash and short–term investments, which included $6.9 million of short–term investments. With regard to our short–term investments, we invest in money market accounts with a major financial institution.

Counterparty Exposure

At December 31, 2010, our open commodity derivative contracts were in a net receivable position with a fair value of $116.0 million. All of our commodity derivative contracts are with major financial institutions who are also lenders under our credit facility. Should one of these financial counterparties not perform, we may not realize the benefit of some of our derivative instruments under lower commodity prices and we could incur a loss. As of December 31, 2010, all of our counterparties have performed pursuant to their commodity derivative contracts.

Cash Flows

Cash flows provided (used) by type of activity were as follows for the years ended December 31:

	2010	2009	2008
Operating activities	$ 122,353	$ 109,525	$ 104,371
Investing activities	(550,559)	(53,917)	(210,009)
Financing activities	432,527	(78,430)	137,046

Operating Activities

Cash flows from operating activities provided $122.4 million and $109.5 million in 2010 and 2009, respectively. The increase was primarily due to higher production and prices for oil, natural gas and natural gas liquids, partially offset by lower realized gains on derivatives and higher operating expenses.

Cash flows from operating activities provided $109.5 million and $104.4 million in 2009 and 2008, respectively. The increase was primarily due to increases in production levels from our acquisitions of oil and natural gas properties in 2009 and 2008 and realized gains on derivatives partially offset by changes in working capital at December 31, 2009 compared with December 31, 2008. The underlying driver of the change in working capital was decreased prices for oil and natural gas in 2009 compared with 2008.

Investing Activities

Our principal recurring investing activity is the acquisition and development of oil and natural gas properties. During 2010, we spent $568.4 million on the acquisitions of oil and natural gas properties and $26.5 million for the development of our oil and natural gas properties. In addition, we received $44.4 million for the sales of oil and natural gas properties. During 2009, we spent $39.6 million on acquisitions of oil and natural gas properties and $14.3 million for the development of our oil and natural gas properties. During 2008, we spent $177.0 million on acquisitions of oil and natural gas properties and $33.0 million for the development of our oil and natural gas properties.

Financing Activities

During 2010, we received net proceeds of $204.7 million from our public equity offerings in February 2010 and August 2010, and we received contributions of $4.3 million from our general partner in order to maintain its 2% interest in us. We borrowed $543.0 million under our credit facility to finance our acquisitions of oil and natural gas properties and we repaid $226.0 million of borrowings outstanding under our credit facility with proceeds from our public equity offerings and cash flows from operations. In addition, we paid distributions of $92.9 million to holders of our common units and our general partner.

During 2009, we received net proceeds of $148.6 million from our public equity offerings in June 2009 and September 2009, and we received contributions of $3.1 million from our general partner in order to maintain its 2% interest in us. We borrowed $20.0 million under our credit facility to finance our acquisition of oil and natural gas properties in November 2009 and we repaid $185.0 million of borrowings outstanding under our credit facility with proceeds from our public equity offerings and cash flows from operations. In addition, we paid distributions of $65.0 million to holders of our common and subordinated units and our general partner.

During 2008, we borrowed $197.0 million under our credit facility to finance our acquisitions of oil and natural gas properties in 2008 and we paid distributions of $45.3 million to holders of our common and subordinated units and our general partner. In addition, as we acquired the San Juan Basin oil and natural gas properties from institutional partnerships managed by EnerVest, we carried over the historical costs related to EnerVest’s interests and applied purchase accounting to the remaining interests and recorded deemed distributions of $13.9 million related to the difference between the purchase price allocation and the amount paid for the San Juan acquisition.

Capital Requirements

We currently expect 2011 spending for the development of our oil and natural gas properties to be between $65.0 million and $80.0 million.

In 2011, we also currently expect to make distributions of approximately $105.9 million to holders of our common units and general partner based on our current quarterly distribution rate of $0.759 per common unit outstanding.

We are actively engaged in the acquisition of oil and natural gas properties. We would expect to finance any significant acquisition of oil and natural gas properties in 2011 through the issuance of equity or debt securities.

Contractual Obligations

In the table below, we set forth our contractual cash obligations as of December 31, 2010. Some of the figures we include in this table are based on our estimates and assumptions about these obligations, including their duration, anticipated actions by third parties and other factors. The contractual cash obligations we will actually pay in future periods may vary from those reflected in the table because the estimates and assumptions are subjective. Amounts in the table represent obligations where both the timing and amount of payment streams are known.

	Payments Due by Period (amounts in thousands)				
	Total	Less Than 1 Year	1 – 3 Years	4 – 5 Years	After 5 Years
Total debt	$ 619,000	$ –	$ 619,000	$ –	$ –
Estimated interest payments [1]	37,047	21,170	15,877	–	–
Purchase obligation [2]	11,000	11,000	–	–	–
Total	$ 667,047	$ 32,170	$ 634,877	$ –	$ –

(1) Amounts represent the expected cash payments for interest based on the debt outstanding and the weighted average effective interest rate of 3.42% as of December 31, 2010. Such amounts do not include the effects of our interest rate swaps.

(2) Amounts represent payments to be made under our omnibus agreement with EnerVest based on the amount that we pay as of December 31, 2010. This amount will increase or decrease as we purchase or divest assets. While these payments will continue for periods subsequent to December 31, 2011, no amounts are shown as they cannot be quantified.

Our asset retirement obligations are not included in the table above given the uncertainty regarding the actual timing of such expenditures. The total amount of our asset retirement obligations at December 31, 2010 is $68.4 million.

Off–Balance Sheet Arrangements

As of December 31, 2010, we had no off–balance sheet arrangements.

RECENT ACCOUNTING STANDARDS

No new accounting pronouncements issued or effective during the year ended December 31, 2010 have had or are expected to have a material impact on our consolidated financial statements.

FORWARD–LOOKING STATEMENTS

This Form 10–K contains forward–looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Exchange Act (each a “forward–looking statement”). These forward–looking statements relate to, among other things, the following:

- our future financial and operating performance and results;
- our business strategy;
- our estimated net proved reserves and standardized measure;
- market prices;
- our future derivative activities; and
- our plans and forecasts.

We have based these forward–looking statements on our current assumptions, expectations and projections about future events.

The words “anticipate,” “believe,” “ensure,” “expect,” “if,” “intend,” “estimate,” “project,” “forecasts,” “predict,” “outlook,” “aim,” “will,” “could,” “should,” “would,” “may,” “likely” and similar expressions, and the negative thereof, are intended to identify forward–looking statements. These statements discuss future expectations, contain projections of results of operations or of financial condition or state other “forward–looking” information. We do not undertake any obligation to update or revise publicly any forward–looking statements, except as required by law. These statements also involve risks and uncertainties that could cause our actual results or financial condition to materially differ from our expectations in this Form 10–K including, but not limited to:

- fluctuations in prices of oil and natural gas;
- significant disruptions in the financial markets;
- future capital requirements and availability of financing;
- uncertainty inherent in estimating our reserves;
- risks associated with drilling and operating wells;
- discovery, acquisition, development and replacement of oil and natural gas reserves;
- cash flows and liquidity;
- timing and amount of future production of oil and natural gas;
- availability of drilling and production equipment;
- marketing of oil and natural gas;
- developments in oil and natural gas producing countries;
- competition;
- general economic conditions;
- governmental regulations;
- receipt of amounts owed to us by purchasers of our production and counterparties to our derivative financial instrument contracts;
- hedging decisions, including whether or not to enter into derivative financial instruments;
- events similar to those of September 11, 2001;
- actions of third party co–owners of interest in properties in which we also own an interest;
- fluctuations in interest rates and the value of the U.S. dollar in international currency markets; and
- our ability to effectively integrate companies and properties that we acquire.

All of our forward–looking information is subject to risks and uncertainties that could cause actual results to differ materially from the results expected. Although it is not possible to identify all factors, these risks and uncertainties include the risk factors and the timing of any of those risk factors identified in the “Risk Factors” section included in Item 1A.

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for oil and natural gas. Declines in oil or natural gas prices may materially adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower oil or natural gas prices also may reduce the amount of oil or natural gas that we can produce economically. A decline in oil and/or natural gas prices could have a material adverse effect on the estimated value and estimated quantities of our oil and natural gas reserves, our ability to fund our operations and our financial condition, cash flows, results of operations and access to capital. Historically, oil and natural gas prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to certain market risks that are inherent in our financial statements that arise in the normal course of business. We may enter into derivative instruments to manage or reduce market risk, but do not enter into derivative agreements for speculative purposes.

We do not designate these or future derivative instruments as hedges for accounting purposes. Accordingly, the changes in the fair value of these instruments are recognized currently in earnings.

Commodity Price Risk

Our major market risk exposure is to prices for oil, natural gas and natural gas liquids. These prices have historically been volatile. As such, future earnings are subject to change due to changes in these prices. Realized prices are primarily driven by the prevailing worldwide price for oil and regional spot prices for natural gas production. We have used, and expect to continue to use, oil and natural gas commodity contracts to reduce our risk of changes in the prices of oil and natural gas. Pursuant to our risk management policy, we engage in these activities as a hedging mechanism against price volatility associated with pre–existing or anticipated sales of oil and natural gas.

We have entered into commodity contracts to hedge significant amounts of our anticipated oil and natural gas production through August 2014. As of December 31, 2010, we have commodity contracts covering approximately 44% of our production attributable to our estimated net proved reserves through August 2014, as estimated in our reserve report prepared by third party engineers using prices, costs and other assumptions required by SEC rules. Subsequent to December 31, 2010, we entered into additional commodity contracts and now have commodity contracts covering approximately 53% of our production through 2014. Our actual production will vary from the amounts estimated in our reserve reports, perhaps materially. Please read the disclosures under “Our estimated oil and natural gas reserve quantities and future production rates are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or the underlying assumptions will materially affect the quantities and present value of our reserves” in the “Risk Factors” section included in Item 1A.

The fair value of our oil and natural gas commodity contracts and basis swaps at December 31, 2010 was a net asset of $116.0 million. A 10% change in oil and natural gas prices with all other factors held constant would result in a change in the fair value (generally correlated to our estimated future net cash flows from such instruments) of our oil and natural gas commodity contracts and basis swaps of approximately $29.2 million. Please see “Item 8. Financial Statements and Supplementary Data” contained herein for additional information.

Interest Rate Risk

Our floating rate credit facility also exposes us to risks associated with changes in interest rates and as such, future earnings are subject to change due to changes in these interest rates. The fair value of our interest rate swaps at December 31, 2010 was a net liability of $12.3 million. If interest rates on our facility increased by 1%, interest expense for the year ended December 31, 2010 would have increased by approximately $3.0 million. Please see “Item 8. Financial Statements and Supplementary Data” contained herein for additional information.

The following table sets forth the required cash payments for our long–term debt and the related weighted average effective interest rate as of December 31, 2010:

	Expected Maturity Date							Fair
	2011	2012	2013	2014	2015	Thereafter	Total	Value
Long–term debt:								
Variable		$ 619,000					$ 619,000	$ 619,000
Average interest rate							3.42%	

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management, including our Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining effective internal control over our financial reporting. Our internal control system was designed to provide reasonable assurance to our Management and Directors regarding the preparation and fair presentation of published 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.

Management conducted an evaluation of the effectiveness of internal control over financial reporting based on the *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that EV Energy Partners, L.P.'s internal control over financial reporting was effective as of December 31, 2010.

Deloitte & Touche LLP, our independent registered public accounting firm, has issued an attestation report on the effectiveness on our internal control over financial reporting as of December 31, 2010 which is included in "Item 8. Financial Statements and Supplementary Data" contained herein.

/s/ JOHN B. WALKER
John B. Walker
Chief Executive Officer of EV Management, LLC,
general partner of EV Energy, GP, L.P.,
general partner of EV Energy Partners, L.P.

/s/ MICHAEL E. MERCER
Michael E. Mercer
Chief Financial Officer of EV Management, LLC,
general partner of EV Energy GP, L.P.,
general partner of EV Energy Partners, L.P.

Houston, TX
February 28, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of EV Management, LLC
and Unitholders of EV Energy Partners, L.P. and Subsidiaries
Houston, Texas

We have audited the accompanying consolidated balance sheets of EV Energy Partners, L.P. and subsidiaries (the "Partnership") as of December 31, 2010 and 2009, and the related consolidated statements of operations, cash flows, and changes in owners' equity of the Partnership for each of the three years in the period ended December 31, 2010. We also have audited the Partnership'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 Partnership's management is responsible for these financial statements, 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 *Management's Report on Internal Control Over Financial Reporting.* Our responsibility is to express an opinion on these financial statements and an opinion on the Partnership's internal control over financial reporting 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 and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting 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 audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Partnership as of December 31, 2010 and 2009, and the results of their operations and their 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. Also, in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010 based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission

As discussed in Note 2 to the consolidated financial statements, the Partnership changed its method of accounting during 2009 for (1) oil and natural gas reserves and disclosures and (2) business combinations.

/s/DELOITTE & TOUCHE LLP
Houston, Texas
February 28, 2011

EV Energy Partners, L.P.
Consolidated Balance Sheets
(In thousands, except number of units)

	December 31, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 23,127	$ 18,806
Accounts receivable:		
Oil, natural gas and natural gas liquids revenues	27,742	14,599
Related party	–	2,881
Other	441	1,034
Derivative asset	55,100	26,733
Other current assets	1,158	625
Total current assets	107,568	64,678
Oil and natural gas properties, net of accumulated depreciation, depletion and amortization; December 31, 2010, $176,897; December 31, 2009, $121,970	1,324,240	771,752
Other property, net of accumulated depreciation and amortization; December 31, 2010, $465; December 31, 2009, $319	1,567	742
Long–term derivative asset	51,497	68,549
Other assets	1,885	1,984
Total assets	$ 1,486,757	$ 907,705
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities:		
Third party	$ 20,678	$ 10,310
Related party	182	–
Derivative liability	1,943	1,543
Total current liabilities	22,803	11,853
Asset retirement obligations	67,175	42,533
Long–term debt	619,000	302,000
Other long–term liabilities	3,048	3,212
Long–term derivative liability	784	676
Commitments and contingencies		
Owners' equity:		
Common unitholders – 30,510,313 units and 23,475,471 units issued and outstanding as of December 31, 2010 and 2009, respectively	779,327	548,160
General partner interest	(5,380)	(729)
Total owners' equity	773,947	547,431
Total liabilities and owners' equity	$ 1,486,757	$ 907,705

See accompanying notes to consolidated financial statements.

EV Energy Partners, L.P.
Consolidated Statements of Operations
(In thousands, except per unit data)

	Year Ended December 31,		
	2010	**2009**	**2008**
Revenues:			
Oil, natural gas and natural gas liquids revenues	$ 165,738	$ 114,066	$ 192,757
Gain on derivatives, net	–	–	1,597
Transportation and marketing–related revenues	5,780	7,846	12,959
Total revenues	171,518	121,912	207,313
Operating costs and expenses:			
Lease operating expenses	53,736	41,495	42,681
Cost of purchased natural gas	4,353	4,509	9,849
Dry hole and exploration costs	417	–	–
Production taxes	7,867	5,983	9,088
Asset retirement obligations accretion expense	3,153	2,035	1,434
Depreciation, depletion and amortization	55,221	52,048	38,032
General and administrative expenses	23,313	18,556	13,653
Gain on sales of oil and natural gas properties	(40,656)	–	–
Total operating costs and expenses	107,404	124,626	114,737
Operating income (loss)	64,114	(2,714)	92,576
Other income (expense), net:			
Realized gains (losses) on derivatives, net	49,042	68,984	(14,557)
Unrealized gains (losses) on derivatives, net	2,994	(51,665)	163,270
Interest expense	(10,442)	(12,321)	(16,128)
Other income (expense), net	628	(626)	559
Total other income, net	42,222	4,372	133,144
Income before income taxes	106,336	1,658	225,720
Income taxes	(285)	(248)	(235)
Net income	$ 106,051	$ 1,410	$ 225,485
General partner's interest in net income, including incentive distribution rights	$ 11,938	$ 7,040	$ 8,847
Limited partners' interest in net income (loss)	$ 94,113	$ (5,630)	$ 216,638
Net income (loss) per limited partner unit:			
Basic	$ 3.35	$ (0.29)	$ 14.12
Diluted	$ 3.34	$ (0.29)	$ 14.12
Weighted average limited partner units outstanding:			
Basic	28,095	19,302	15,340
Diluted	28,162	19,302	15,340

See accompanying notes to consolidated financial statements.

EV Energy Partners, L.P.
Consolidated Statements of Cash Flows
(In thousands)

	Year Ended December 31, 2010	2009	2008
Cash flows from operating activities:			
Net income	$ 106,051	$ 1,410	$ 225,485
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Dry hole costs	170	–	–
Asset retirement obligations accretion expense	3,153	2,035	1,434
Depreciation, depletion and amortization	55,221	52,048	38,032
Equity–based compensation	5,043	3,659	1,241
Gain on sales of oil and natural gas properties	(40,656)	–	–
Unrealized (gains) losses on derivatives, net	(2,994)	51,665	(164,867)
Amortization of deferred loan costs	564	799	370
Other	(169)	544	–
Changes in operating assets and liabilities:			
Accounts receivable	(9,320)	3,955	327
Other current assets	2,215	214	(151)
Accounts payable and accrued liabilities	4,514	(2,126)	(233)
Deferred revenues	–	(4,120)	2,998
Long–term liabilities	(734)	–	–
Other, net	(705)	(558)	(265)
Net cash flows provided by operating activities	122,353	109,525	104,371
Cash flows from investing activities:			
Acquisitions of oil and natural gas properties	(568,433)	(39,646)	(176,992)
Development of oil and natural gas properties	(26,525)	(14,271)	(33,017)
Proceeds from sales of oil and natural gas properties	44,399	–	–
Net cash flows used in investing activities	(550,559)	(53,917)	(210,009)
Cash flows from financing activities:			
Long–term debt borrowings	543,000	20,000	197,000
Repayments of long–term debt borrowings	(226,000)	(185,000)	–
Proceeds from equity offerings	204,965	149,038	–
Offering costs	(306)	(484)	–
Distributions related to acquisitions	–	–	(13,918)
Loan costs incurred	(465)	(44)	(1,331)
Contributions from general partner	4,267	3,077	601
Distributions to partners	(92,934)	(65,017)	(45,306)
Net cash flows provided by (used in) financing activities	432,527	(78,430)	137,046
Increase (decrease) in cash and cash equivalents	4,321	(22,822)	31,408
Cash and cash equivalents – beginning of period	18,806	41,628	10,220
Cash and cash equivalents – end of period	$ 23,127	$ 18,806	$ 41,628

See accompanying notes to consolidated financial statements.

EV Energy Partners, L.P.
Consolidated Statements of Changes in Owners' Equity
(In thousands)

	Common Unitholders	Subordinated Unitholders	General Partner Interest	Accumulated Other Comprehensive Income	Total Owners' Equity
Balance, December 31, 2007	$ 282,676	$ (5,488)	$ 4,245	$ 1,597	$ 283,030
Conversion of 42,500 vested phantom units	1,262	–	–	–	1,262
Contributions from general partner	–	–	601	–	601
Issuance of 1,145,123 common units in conjunction with acquisition of oil and natural gas properties	7,927	–	–	–	7,927
Distributions in conjunction with acquisitions	(5,453)	(7,390)	(1,075)	–	(13,918)
Distributions	(32,582)	(8,278)	(4,446)	–	(45,306)
Comprehensive income:					
Net income	178,201	42,774	4,510	–	
Reclassification adjustment into earnings	–	–	–	(1,597)	
Total comprehensive income					223,888
Balance, December 31, 2008	432,031	21,618	3,835	–	457,484
Conversion of 103,409 vested phantom units	1,706	–	–	–	1,706
Proceeds from public equity offerings	149,038	–	–	–	149,038
Offering costs	(484)	–	–	–	(484)
Contributions from general partner	–	–	3,077	–	3,077
Distributions	(48,016)	(9,331)	(7,670)	–	(65,017)
Equity–based compensation	217	–	–	–	217
Conversion of subordinated units	13,176	(13,176)	–	–	–
Net income	492	889	29	–	1,410
Balance, December 31, 2009	548,160	–	(729)	–	547,431
Conversion of 84,842 vested phantom units	2,580	–	–	–	2,580
Proceeds from public equity offerings	204,965	–	–	–	204,965
Offering costs	(306)	–	–	–	(306)
Contributions from general partner	–	–	4,267	–	4,267
Distributions	(81,895)	–	(11,039)	–	(92,934)
Equity–based compensation	1,893	–	–	–	1,893
Net income	103,930	–	2,121	–	106,051
Balance, December 31, 2010	$ 779,327	$ –	$ (5,380)	$ –	$ 773,947

See accompanying notes to consolidated financial statements.

NOTE 1. ORGANIZATION AND NATURE OF BUSINESS

EV Energy Partners, L.P. (the "Partnership") is a publicly held limited partnership that engages in the acquisition, development and production of oil and natural gas properties. The Partnership's general partner is EV Energy GP, L.P. ("EV Energy GP"), a Delaware limited partnership, and the general partner of its general partner is EV Management, LLC ("EV Management"), a Delaware limited liability company. EV Management is a wholly owned subsidiary of EnerVest, Ltd. ("EnerVest"), a Texas limited partnership. EnerVest and its affiliates also have a significant interest in the Partnership through their 71.25% ownership of EV Energy GP which, in turn, owns a 2% general partner interest in the Partnership and all of its incentive distribution rights.

NOTE 2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The consolidated financial statements include the operations of the Partnership and all of its wholly–owned subsidiaries ("we," "our" or "us"). All intercompany accounts and transactions have been eliminated in consolidation/combination. In the Notes to Consolidated Financial Statements, all dollar and share amounts in tabulations are in thousands of dollars and shares, respectively, unless otherwise indicated.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and judgments that affect the reported amounts of assets and liabilities, 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. We base our estimates and judgments on historical experience and on various other assumptions and information that are believed to be reasonable under the circumstances. Estimates and assumptions about future events and their effects cannot be perceived with certainty and, accordingly, these estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as our operating environment changes. While we believe that the estimates and assumptions used in the preparation of the consolidated financial statements are appropriate, actual results could differ from those estimates.

Cash and Cash Equivalents

We consider all highly liquid investments with an original maturity of three months or less at the time of purchase to be cash equivalents. All of our cash and cash equivalents are maintained with several major financial institutions in the United States. Deposits with these financial institutions may exceed the amount of insurance provided on such deposits; however, we regularly monitor the financial stability of these financial institutions and believe that we are not exposed to any significant default risk.

Accounts Receivable

Accounts receivable from oil, natural gas and natural gas liquids sales are recorded at the invoiced amount and do not bear interest. We routinely assess the financial strength of our customers and bad debts are recorded based on an account–by–account review after all means of collection have been exhausted, and the potential recovery is considered remote.

As of December 31, 2010 and 2009, we did not have any reserves for doubtful accounts, and we did not incur any expense related to bad debts. We do not have any off–balance sheet credit exposure related to our customers.

Property and Depreciation

Our oil and natural gas producing activities are accounted for under the successful efforts method of accounting. Under this method, exploration costs, other than the costs of drilling exploratory wells, are charged to expense as incurred. Costs that are associated with the drilling of successful exploration wells are capitalized if proved reserves are found. Lease acquisition costs are capitalized when incurred. Capitalized costs associated with unproved properties totaled $7.3 million and $2.8 million as of December 31, 2010 and December 31, 2009, respectively. Costs associated with the drilling of exploratory wells that do not find proved reserves, geological and geophysical costs and costs of certain non–producing leasehold costs are expensed as incurred.

No gains or losses are recognized upon the disposition of oil and natural gas properties except in transactions such as the significant disposition of an amortizable base that significantly affects the unit–of–production amortization rate. Sales proceeds are credited to the carrying value of the properties.

The capitalized costs of our producing oil and natural gas properties are depreciated and depleted by the units–of–production method based on the ratio of current production to estimated total net proved oil and natural gas reserves as estimated by independent petroleum engineers. Proved developed reserves are used in computing unit rates for drilling and development costs and total proved reserves are used for depletion rates of leasehold, platform, and pipeline costs.

Other property is stated at cost less accumulated depreciation, which is computed using the straight–line method based on estimated economic lives ranging from three to 25 years. We expense costs for maintenance and repairs in the period incurred. Significant improvements and betterments are capitalized if they extend the useful life of the asset.

Impairment of Long–Lived Assets

We evaluate our proved oil and natural gas properties and related equipment and facilities for impairment whenever events or changes in circumstances indicate that the carrying amounts of such properties may not be recoverable. The determination of recoverability is made based upon estimated undiscounted future net cash flows. The amount of impairment loss, if any, is determined by comparing the fair value, as determined by a discounted cash flow analysis, with the carrying value of the related asset. For the years ended December 31, 2010, 2009 and 2008, we recorded no impairments related to proved oil and natural gas properties as the carrying amounts of such properties were determined to be recoverable.

Unproved oil and natural gas properties are assessed periodically on a property–by–property basis, and any impairment in value is recognized. For the years ended December 31, 2010, 2009 and 2008, we recorded no impairments related to unproved oil and natural gas properties.

Asset Retirement Obligations

An asset retirement obligation (“ARO”) represents the future abandonment costs of tangible assets, such as platforms, wells, service assets, pipelines, and other facilities. We record an ARO and capitalize the asset retirement cost in oil and natural gas properties in the period in which the retirement obligation is incurred based upon the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon wells. After recording these amounts, the ARO is accreted to its future estimated value using an assumed cost of funds and the additional capitalized costs are depreciated on a unit–of–production basis. If the ARO is settled for an amount other than the recorded amount, a gain or loss is recognized.

Revenue Recognition

Oil, natural gas and natural gas liquids revenues are recognized when production is sold to a purchaser at fixed or determinable prices, when delivery has occurred and title has transferred and collectability of the revenue is reasonably possible. We follow the sales method of accounting for natural gas revenues. Under this method of accounting, revenues are recognized based on volumes sold, which may differ from the volume to which we are entitled based on our working interest. An imbalance is recognized as a liability only when the estimated remaining reserves will not be sufficient to enable the under–produced owner(s) to recoup its entitled share through future production. Under the sales method, no receivables are recorded where we have taken less than our share of production. There were no significant gas imbalances at December 31, 2010 or 2009.

We own and operate a network of natural gas gathering systems in the Monroe field in Northern Louisiana which gather and transport owned natural gas and a small amount of third party natural gas to intrastate, interstate and local distribution pipelines. Natural gas gathering and transportation revenue is recognized when the natural gas has been delivered to a custody transfer point.

Income Taxes

We are a partnership that is not taxable for federal income tax purposes. As such, we do not directly pay federal income tax. As appropriate, our taxable income or loss is includable in the federal income tax returns of our partners. Since we do not have access to information regarding each partner’s tax basis, we cannot readily determine the total difference in the basis of our net assets for financial and tax reporting purposes.

We record our obligations under the Texas gross margin tax as “Income taxes” in our consolidated statement of operations.

Net Income per Limited Partner Unit

Our partnership agreement contains incentive distribution rights. Accordingly, net income used in the determination of net income per limited partner unit for the current reporting period is to be reduced by the amount of available cash that will be distributed to the limited partners, the general partner and the holders of the incentive distribution rights for that reporting period. The undistributed earnings, if any, are then allocated to the limited partners, the general partner and the holders of the incentive distribution rights in accordance with the terms of the partnership agreement. Our partnership agreement does not allow for the distribution of undistributed earnings to the holders of the incentive distribution rights, as it limits distributions to the holders of the incentive distribution rights to available cash as defined in the partnership agreement. Basic and diluted net income per limited partner unit is determined by dividing net income, after deducting the amount allocated to the general partner and the holders of the incentive distribution rights, by the weighted average number of outstanding limited partner units during the period.

Derivatives

We monitor our exposure to various business risks, including commodity price and interest rate risks, and use derivatives to manage the impact of certain of these risks. Our policies do not permit the use of derivatives for speculative purposes. We use energy derivatives for the purpose of mitigating risk resulting from fluctuations in the market price of oil and natural gas.

We have elected not to designate our derivatives as hedging instruments. Changes in the fair value of derivatives are recorded immediately to net income as “Unrealized gains (losses) on derivatives, net” in our consolidated statements of operations.

The counterparties to our derivatives are major financial institutions. The credit ratings and concentration of risk of these financial institutions are monitored on a continuing basis.

Fair Value of Financial Instruments

Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, derivatives and long–term debt. The carrying amounts of our financial instruments other than derivatives and long–term debt approximate fair value because of the short-term nature of the items. Derivatives are recorded at fair value (see Note 6). The carrying value of our debt approximates fair value because the credit facility’s variable interest rate resets frequently and approximates current market rates available to us.

Business Segment Reporting

We operate in one reportable segment engaged in the exploration, development and production of oil and natural gas properties and all of our operations are located in the United States.

Concentration of Credit Risk

Our oil, natural gas and natural gas liquids revenues are derived principally from uncollateralized sales to numerous companies in the oil and natural gas industry; therefore, our customers may be similarly affected by changes in economic and other conditions within the industry. We have experienced no significant credit losses on such sales in the past.

In 2010 and 2009, no customer accounted for greater than 10% of our consolidated oil, natural gas and natural gas liquids revenues. In 2008, three customers accounted for 11%, 10% and 10%, respectively, of our consolidated oil, natural gas and natural gas liquids revenues. We believe that the loss of a major customer would have a temporary effect on our revenues but that over time, we would be able to replace our major customers.

Recent Accounting Standards

In December 2007, the Financial Accounting Standards Board ("FASB") issued new accounting guidance regarding the accounting for business combinations. This new guidance retains the acquisition method of accounting used in business combinations and establishes principles and requirements for the recognition and measurement of assets, liabilities and goodwill, including the requirement that most transaction and restructuring costs related to the acquisition be expensed. In addition, this guidance requires disclosures to enable users to evaluate the nature and financial effects of the business combination. We adopted this new guidance on January 1, 2009 for our acquisitions completed in 2009 and 2010 (see Note 4).

In January 2010, the FASB issued Accounting Standards Update ("ASU") No. 2010–03, *Extractive Activities – Oil and Gas (Topic 932)*, to align the oil and natural gas reserve estimation and disclosure requirements of Topic 932 with the Securities and Exchange Commission's final rule, *Modernization of Oil and Gas Reporting*. ASU No. 2010–03 was effective for annual reporting periods ending on or after December 31, 2009. We adopted the provisions of ASU 2010–03 in our consolidated financial statements beginning in the year ended December 31, 2009 (see Notes 16, 17 and 18).

In January 2010, the FASB issued ASU No. 2010–06, *Fair Value Measurements and Disclosures (Topic 820*), which provides amendments to Topic 820 and requires new disclosures for (i) transfers between Levels 1, 2 and 3 and the reasons for such transfers and (ii) activity in Level 3 fair value measurements to show separate information about purchases, sales, issuances and settlements. In addition, ASU 2010–06 amends Topic 820 to clarify existing disclosures around the disaggregation level of fair value measurements and disclosures for the valuation techniques and inputs utilized (for Level 2 and Level 3 fair value measurements). The provisions in ASU 2010–06 are applicable to interim and annual reporting periods beginning subsequent to December 15, 2009, with the exception of Level 3 disclosures of purchases, sales, issuances and settlements, which will be required in reporting periods beginning after December 15, 2010. The adoption of ASU 2010–06 did not impact our operating results, financial position or cash flows, but did impact our disclosures on fair value measurements (see Note 7).

No other new accounting pronouncements issued or effective during the year ended December 31, 2010 have had or are expected to have a material impact on our unaudited condensed consolidated financial statements.

Subsequent Events

We evaluated subsequent events for appropriate accounting and disclosure through the date these condensed consolidated financial statements were issued

NOTE 3. EQUITY–BASED COMPENSATION

EV Management has a long–term incentive plan (the "Plan") for employees, consultants and directors of EV Management and its affiliates who perform services for us. The Plan, as amended, allows for the award of unit options, phantom units, performance units, restricted units and deferred equity rights. As of December 31, 2010, the aggregate amount of our common units that may be awarded under the plan was 1.5 million units. Unless earlier terminated by us or unless all units available under the Plan have been paid to participants, the Plan will terminate as of the close of business on September 20, 2016. The compensation committee of the board of directors administers the Plan.

In January 2011, the number of common units which we may issue under the Plan was increased from 1.5 million to 4.5 million.

Phantom Units

Liability Awards

We account for the phantom units issued prior to 2009 as liability awards due to the Plan's provision allowing us, at our discretion, to settle the award in either cash or common units and the presumption that some or all of these awards would be settled in cash. The fair value of these phantom units is remeasured at the end of each reporting period based on the current market price of our common units until settlement. Prior to settlement, compensation cost is recognized for these phantom units based on the proportionate amount of the requisite service period that has been rendered to date and is net of estimated forfeitures. These phantom units are subject to graded vesting over a three to four year period.

Activity related to these phantom units is as follows:

Nonvested phantom units as of December 31, 2009	301,121
Vested	(108,971)
Forfeited	(27,716)
Nonvested phantom units as of December 31, 2010	164,434

The total fair value of these phantom units vested in the years ended December 31, 2010, 2009 and 2008 was $3.3 million, $1.7 million and $1.3 million, respectively. Of the units vested in 2010, 84,842 were converted to common units at a fair value of $2.6 million and 24,129 were settled in cash at a fair value of $0.7 million.

We recognized compensation cost related to these phantom units of $3.1 million, $3.4 million and $1.2 million in the years ended December 31, 2010, 2009 and 2008, respectively. These costs are included in “General and administrative expenses” in our consolidated statements of operations.

As of December 31, 2010, there was $2.1 million of total unrecognized compensation cost related to these unvested phantom units which is expected to be recognized over a weighted average period of 2.0 years.

Equity Awards

We account for the phantom units issued beginning in 2009 as equity awards since we have determined that these awards will likely be settled by issuing common units. Compensation cost is recognized for these phantom units on a straight–line basis over the service period and is net of estimated forfeitures. These phantom units are subject to graded vesting over a four year period.

We estimated the fair value of these phantom units using the Black–Scholes option pricing model. The following assumptions were used to estimate the weighted average fair value of these phantom units for the years ended December 31:

	2010	2009
Weighted average fair value of phantom units	$ 37.15	$ 28.68
Expected volatility	48.042%	57.016%
Risk–free interest rate	1.05%	1.16%
Dividend yield (1)	0.0%	0.0%
Expected life (years)	4.0	4.1

(1) The dividend yield is not taken into account as recipients are entitled to receive all distributions underlying these phantom units.

Activity related to these phantom units is as follows:

	Number of Phantom Units	Weighted Average Grant Date Fair Value per Phantom Unit
Nonvested phantom units as of December 31, 2009	249,700	$ 28.68
Granted	361,750	37.15
Forfeited	(30,750)	28.68
Nonvested phantom units as of December 31, 2010	580,700	$ 33.95

We recognized compensation cost related to these phantom units of $1.7 million and $0.1 million in the years ended December 31, 2010 and 2009. This cost is included in “General and administrative expenses” in our consolidated statements of operations.

As of December 31, 2010, there was $17.3 million of total unrecognized compensation cost related to unvested phantom units which is expected to be recognized over a weighted average period of 3.7 years.

Performance Units

In March 2009, we issued 0.3 million performance units to certain employees and executive officers of EV Management and its affiliates. The vesting of these performance units is subject to our common units achieving certain market prices. In June 2009 and December 2009, the performance criterion was achieved with respect to 0.2 million of the performance units and the units vested 25% each year beginning January 15, 2010.

We account for these performance units as equity awards, and we estimated the fair value of these performance units using the Monte Carlo simulation model. The following assumptions were used to estimate the weighted average fair value of the performance units:

Weighted average fair value of performance units	$	2.37
Expected volatility		56.725%
Risk–free interest rate		1.911%
Expected quarterly distribution amount [1]	$	0.751
Expected life (years)		2.85

(1) The fair value of the performance units assumes that the expected quarterly distribution amount will increase at a 3% annual compound growth rate over the five year term of the performance units.

Activity related to these performance units is as follows:

	Number of Phantom Units		Weighted Average Grant Date Fair Value per Phantom Unit
Nonvested performance units as of December 31, 2009	300,000	$	2.37
Vested	(50,000)		2.37
Forfeited	(50,000)		2.37
Nonvested performance units as of December 31, 2010	200,000	$	2.37

The total fair value of these performance units vested in the year ended December 31, 2010 was $0.1 million.

We recognized compensation cost related to our performance units of $0.1 million in each of the years ended December 31, 2010 and 2009. This cost is included in “General and administrative expenses” in our consolidated statements of operations.

As of December 31, 2010, there was $0.3 million of total unrecognized compensation cost related to unvested performance units which is expected to be recognized over a weighted average period of 2.0 years.

NOTE 4. ACQUISITIONS

2010

On March 30, 2010 followed by a second closing on June 29, 2010, we, along with certain institutional partnerships managed by EnerVest, acquired oil and natural gas properties in the Appalachian Basin. We acquired a 46.15% proportional interest in these properties for $145.8 million. We recognized $20.2 million of oil, natural gas and natural gas liquids revenues related to this acquisition in our consolidated statement of operations for the year ended December 31, 2010.

On September 29, 2010, we acquired oil and natural gas properties in the Mid–Continent area for $119.9 million, subject to customary closing conditions and purchase price adjustments. We recognized $6.8 million of oil, natural gas and natural gas liquids revenues related to this acquisition in our consolidated statement of operations for the year ended December 31, 2010.

On December 30, 2010, we, along with certain institutional partnerships managed by EnerVest, acquired oil and natural gas properties in the Barnett Shale, including certain related derivatives. We acquired a 31.02% proportional interest in these properties for $295.8 million, subject to customary closing conditions and purchase price adjustments. We recognized $0.2 million of oil, natural gas and natural gas liquids revenues related to this acquisition in our consolidated statement of operations for the year ended December 31, 2010.

The following table reflects pro forma revenues, net income and net income (loss) per limited partner unit for the years ended December 31 as if these acquisitions had taken place on January 1, 2009. These unaudited pro forma amounts do not purport to be indicative of the results that would have actually been obtained during the periods presented or that may be obtained in the future.

	2010	2009
Revenues	$ 241,285	$ 206,699
Net income	121,822	7,779
Net income per limited partner unit:		
Basic	$ 3.90	$ 0.03
Diluted	$ 3.89	$ 0.03

In addition to the acquisitions described above, in 2010, we, along with certain institutional partnerships managed by EnerVest, acquired oil and natural gas properties in the Appalachian Basin, the San Juan Basin and Central and East Texas for an aggregate purchase price of $7.0 million.

The recognized fair values of the identifiable assets acquired and liabilities assumed in connection with these acquisitions are as follows:

Accounts receivable	$ 136
Derivative asset	5,397
Other current assets	2,748
Oil and natural gas properties	579,609
Other property	1,036
Long–term derivative asset	2,638
Accounts payable and accrued liabilities	(79)
Derivative liability	(139)
Asset retirement obligations	(22,831)
Long–term derivative liability	(82)
	$ 568,433

The amounts included in the table above for the September 2010 acquisition and the December 2010 acquisition represent preliminary estimates of the fair values of the identifiable assets acquired and liabilities assumed for these acquisitions. We expect to finalize these fair values in the first and second quarters of 2011, respectively.

2009

In July 2009, we, along with certain institutional partnerships managed by EnerVest, acquired additional oil and natural gas properties in the Austin Chalk area in Central and East Texas. We acquired a 15.15% proportional interest in these properties for $12.0 million.

In September 2009, we, along with certain institutional partnerships managed by EnerVest, acquired additional oil and natural gas properties in the Austin Chalk area in Central and East Texas. We acquired a 15.15% proportional interest in these properties for $5.0 million.

In November 2009, we, along with certain institutional partnerships managed by EnerVest, acquired additional oil and natural gas properties in the Appalachian Basin. We acquired a 17.2% proportional interest in these properties for $22.6 million.

The recognized fair value of the identifiable assets acquired and liabilities assumed in connection with these acquisitions are as follows:

Accounts receivable	$ 141
Other current assets	409
Oil and natural gas properties	44,068
Other property	597
Accounts payable and accrued liabilities	(53)
Asset retirement obligations	(5,516)
	$ 39,646

NOTE 5. DIVESTITURES

On March 1, 2010, we sold 14 non–core oil and natural gas wells and recorded a loss on the sale of $0.6 million.

On June 14, 2010, we sold unproved oil and natural gas properties and recorded a gain on the sale of $4.4 million.

On July 1, 2010, we sold unproved oil and natural gas properties for $39.9 million and recorded a gain on the sale of $36.8 million.

NOTE 6. RISK MANAGEMENT

Our business activities expose us to risks associated with changes in the market price of oil, natural gas and natural gas liquids. In addition, our floating rate credit facility exposes us to risks associated with changes in interest rates. As such, future earnings are subject to fluctuation due to changes in both the market price of oil, natural gas and natural gas liquids and interest rates. We use derivatives to reduce our risk of changes in the prices of oil and natural gas and interest rates. Our policies do not permit the use of derivatives for speculative purposes.

We have elected not to designate any of our derivatives as hedging instruments. Accordingly, changes in the fair value of our derivatives are recorded immediately to net income as “Unrealized gains (losses) on derivatives, net” in our consolidated statements of operations.

As of December 31, 2010, we had entered into oil and natural gas commodity contracts with the following terms:

Period Covered	Index	Hedged Volume	Weighted Average Fixed Price	Weighted Average Floor Price	Weighted Average Ceiling Price
Oil (MBbls):					
Swap – 1st quarter 2011	WTI	31.5	$ 91.00	$	$
Swap – 2nd quarter 2011	WTI	27.3	91.00		
Swap – 3rd quarter 2011	WTI	20.7	91.00		
Swap – 4th quarter 2011	WTI	15.2	91.00		
Swaps – 2011	WTI	344.2	95.84		
Collars – 2011	WTI	469.4		105.66	156.16
Swaps – 2012	WTI	287.3	97.70		
Collars – 2012	WTI	456.8		104.54	156.77
Swaps – 2013	WTI	511.0	78.64		
Swap – January 2014 through July 2014	WTI	106.0	84.60		
Swaps – January 2014 through August 2014	WTI	194.4	82.28		
Ethane (MBbls):					
Swap – 1st quarter 2011	Mont Belvieu (Non-TET)-OPIS	51.8	24.99		
Swap – 2nd quarter 2011	Mont Belvieu (Non-TET)-OPIS	50.1	21.95		
Swap – 3rd quarter 2011	Mont Belvieu (Non-TET)-OPIS	48.3	20.16		
Swap – 4th quarter 2011	Mont Belvieu (Non-TET)-OPIS	46.0	19.64		
Propane (MBbls):					
Swap – 1st quarter 2011	Mont Belvieu (Non-TET)-OPIS	63.0	53.19		
Swap – 2nd quarter 2011	Mont Belvieu (Non-TET)-OPIS	59.2	49.20		
Swap – 3rd quarter 2011	Mont Belvieu (Non-TET)-OPIS	57.5	49.36		
Swap – 4th quarter 2011	Mont Belvieu (Non-TET)-OPIS	55.2	50.20		
Natural Gas (MmmBtus):					
Swap – 2011	Dominion Appalachia	912.5	8.69		
Collar – 2011	Dominion Appalachia	1,095.0		9.00	12.15
Collar – 2012	Dominion Appalachia	1,830.0		8.95	11.45
Swap – 1st quarter 2011	NYMEX	585.0	4.50		
Swap – 2nd quarter 2011	NYMEX	364.0	4.47		
Swap – 3rd quarter 2011	NYMEX	184.0	4.58		
Swaps – 2011	NYMEX	14,320.0	6.43		
Collars – 2011	NYMEX	1,572.8		5.90	7.03
Swaps – 2012	NYMEX	10,467.6	7.21		
Collar – 2012	NYMEX	2,043.7		6.22	6.94
Swaps – 2013	NYMEX	7,117.5	6.15		
Swaps – January 2014 through August 2014	NYMEX	1,215.0	7.06		
Collar – 2011	MICHCON_NB	1,642.5		8.70	11.85
Collar – 2012	MICHCON_NB	1,647.0		8.75	11.05
Collar – 2011	HOUSTON SC	1,277.5		8.25	11.65
Collar – 2012	HOUSTON SC	1,098.0		8.25	11.10
Swap – 2011	EL PASO PERMIAN	912.5	9.30		
Swap – 2012	EL PASO PERMIAN	732.0	9.21		
Swap – 2013	EL PASO PERMIAN	1,095.0	6.77		
Swap – 2013	SAN JUAN BASIN	1,095.0	6.66		
Collars – 2011	NGPL TEX/OK	1,019.1		5.75	6.58

As of December 31, 2010, we had also entered into natural gas basis swaps with the following terms:

Period Covered	Floating Index 1	Floating Index 2	Hedged Volume	Spread
2011	NYMEX	Dominion Appalachia	346.0	0.1975
2011	NYMEX	Appalachia Columbia	94.5	0.1500

As of December 31, 2010, we had also entered into interest rate swaps with the following terms:

Period Covered	Notional Amount	Floating Rate	Fixed Rate
January 2011 – July 2012	$ 200,000	1 Month LIBOR	4.163%
January 2011 – September 2012	40,000	1 Month LIBOR	2.145%

The fair value of these derivatives was as follows as of December 31:

	Asset Derivatives		Liability Derivatives	
	2010	**2009**	**2010**	**2009**
Commodity contracts	$ 123,655	$ 111,541	$ 7,633	$ 6,413
Interest rate swaps	–	–	12,152	12,065
Total fair value	123,655	111,541	19,785	18,478
Netting arrangements	(17,058)	(16,259)	(17,058)	(16,259)
Net recorded fair value	$ 106,597	$ 95,282	$ 2,727	$ 2,219
Location of derivatives on our consolidated balance sheets:				
Derivative asset	$ 55,100	$ 26,733	$ –	$ –
Long–term derivative asset	51,497	68,549	–	–
Derivative liability	–	–	1,943	1,543
Long–term derivative liability	–	–	784	676
	$ 106,597	$ 95,282	$ 2,727	$ 2,219

The following table presents the impact of derivatives and their location within the consolidated statements of operations for the years ended December 31:

	2010	**2009**	**2008**
Realized gains (losses) on derivatives, net:			
Commodity contracts	$ 57,694	$ 77,335	$ (12,959)
Interest rate swaps	(8,652)	(8,351)	(1,598)
Total	$ 49,042	$ 68,984	$ (14,557)
Unrealized gains (losses) on derivatives, net:			
Commodity contracts	$ 3,081	$ (55,580)	$ 179,250
Interest rate swaps	(87)	3,915	(15,980)
Total	$ 2,994	$ (51,665)	$ 163,270

During the year ended December 31, 2008, we reclassified $1.6 million from Accumulated Other Comprehensive Income to “Gain on derivatives, net” related to derivatives where we removed the previous hedge designation.

NOTE 7. FAIR VALUE MEASUREMENTS

The following table presents the fair value hierarchy table for our net assets and liabilities that are required to be measured at fair value on a recurring basis:

		Fair Value at Reporting Date Using:		
	Total Carrying Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
December 31, 2010:				
Derivative assets:				
Commodity contracts	$ 123,655	$ –	$ 123,655	$ –
Derivative liabilities:				
Commodity contracts	$ 7,633	–	$ 7,633	$ –
Interest rate swaps	12,152	–	12,152	–
Total derivative liabilities	$ 19,785	$ –	$ 19,785	$ –
December 31, 2009:				
Derivative assets:				
Commodity contracts	$ 111,541	$ –	$ 111,541	$ –
Derivative liabilities:				
Commodity contracts	$ 6,413	$ –	$ 6,413	$ –
Interest rate swaps	12,065	–	12,065	–
Total derivative liabilities	$ 18,478	$ –	$ 18,478	$ –

Our derivatives consist of over–the–counter ("OTC") contracts which are not traded on a public exchange. These derivatives are indexed to active trading hubs for the underlying commodity, and are OTC contracts commonly used in the energy industry and offered by a number of financial institutions and large energy companies.

As the fair value of these derivatives is based on inputs using market prices obtained from independent brokers or determined using quantitative models that use as their basis readily observable market parameters that are actively quoted and can be validated through external sources, including third party pricing services, brokers and market transactions, we have categorized these derivatives as Level 2. We value these derivatives based on observable market data for similar instruments. This observable data includes the forward curve for commodity prices based on quoted market prices and prospective volatility factors related to changes in the forward curves and yield curves based on money market rates and interest rate swap data. Our estimates of fair value have been determined at discrete points in time based on relevant market data. These estimates involve uncertainty and cannot be determined with precision. There were no changes in valuation techniques or related inputs in the year ended December 31, 2010.

NOTE 8. ASSET RETIREMENT OBLIGATIONS

The changes in the aggregate ARO are as follows:

Balance as of December 31, 2008	$	34,615
Liabilities incurred and assumed in acquisitions		5,958
Accretion expense		2,035
Revisions in estimated cash flows		1,749
Payments to settle liabilities		(669)
Balance as of December 31, 2009		43,688
Liabilities incurred and assumed in acquisitions		23,488
Sale of oil and natural gas properties		(292)
Accretion expense		3,153
Revisions in estimated cash flows		(902)
Payments to settle liabilities		(705)
Balance as of December 31, 2010	$	68,430

As of December 31, 2010 and 2009, $1.3 million and $1.2 million, respectively, of our ARO is classified as current and is included in “Accounts payable and accrued liabilities” on our consolidated balance sheets.

NOTE 9. LONG–TERM DEBT

As of December 31, 2010, our credit facility consists of a $700.0 million senior secured revolving credit facility that expires in October 2012. Borrowings under the facility are secured by a first priority lien on substantially all of our assets and the assets of our subsidiaries. We may use borrowings under the facility for acquiring and developing oil and natural gas properties, for working capital purposes, for general corporate purposes and for funding distributions to partners. We also may use up to $50.0 million of available borrowing capacity for letters of credit. The facility requires the maintenance of a current ratio (as defined in the facility) of greater than 1.0 and a ratio of total debt to earnings plus interest expense, taxes, depreciation, depletion and amortization expense and exploration expense of no greater than 4.0 to 1.0. As of December 31, 2010, we were in compliance with these financial covenants.

Borrowings under the facility bear interest at a floating rate based on, at our election, a base rate or the London Inter–Bank Offered Rate plus applicable premiums based on the percent of the borrowing base that we have outstanding (weighted average effective interest rate of 3.42% and 3.23% at December 31, 2010 and 2009, respectively).

Borrowings under the facility may not exceed a “borrowing base” determined by the lenders based on our oil and natural gas reserves. As of December 31, 2010, the borrowing base was $700.0 million. The borrowing base is subject to scheduled redeterminations as of April 1 and October 1 of each year with an additional redetermination once per calendar year at our request or at the request of the lenders and with one calculation that may be made at our request during each calendar year in connection with material acquisitions or divestitures of properties.

The facility also provides that if we issue senior debt between scheduled redetermination dates other than in conjunction with an interim redetermination, the borrowing base then in effect on the date on which such senior debt is issued will be reduced by an amount equal to the product of 0.30 multiplied by the stated principal amount of such senior debt.

We had $619.0 million and $302.0 million outstanding under the facility at December 31, 2010 and 2009, respectively.

NOTE 10. COMMITMENTS AND CONTINGENCIES

We are involved in disputes or legal actions arising in the ordinary course of business. We do not believe the outcome of such disputes or legal actions will have a material adverse effect on our consolidated financial statements, and no amounts have been accrued at December 31, 2010 and 2009.

NOTE 11. OWNERS' EQUITY

Issuance of Units

In September 2008, we issued a total of 1,145,123 common units to EnerVest in conjunction with our acquisition of natural gas properties in West Virginia and oil and natural gas properties in the San Juan Basin.

In June 2009 and September 2009, we closed public offerings of 4.025 million common units and 3.22 million common units, respectively, at offering prices of $20.40 per common unit and $22.83 per common unit, respectively. We received net proceeds of $151.6 million, including contributions of $3.1 million by our general partner to maintain its 2% interest in us.

In February 2010 and August 2010, we closed public offerings of 3.45 million and 3.45 million common units, respectively, at offering prices of $28.08 per common unit and $33.97 per common unit, respectively. We received net proceeds of $208.9 million, including contributions of $4.3 million by our general partner to maintain its 2% interest in us.

Units Outstanding

At December 31, 2010, owner's equity consists of 30,510,313 common units outstanding (including 1,501,354 common units held by affiliates of EV Management, including executive officers), representing a 98% limited partnership interest in us, and a 2% general partnership interest.

Common Units

The common units have limited voting rights as set forth in our partnership agreement.

Pursuant to our partnership agreement, if at any time our general partner and its affiliates own more than 80% of the common units outstanding, our general partner has the right, but not the obligation, to "call" or acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then current market value. Our general partner may assign this call right to any of its affiliates or to us.

General Partner Interest

Our general partner owns a 2% interest in us. This interest entitles our general partner to receive distributions of available cash from operating surplus as discussed further below under Cash Distributions. Our partnership agreement sets forth the calculation to be used to determine the amount and priority of cash distributions that the common unitholders and general partner will receive.

The general partner has the management rights as set forth in our partnership agreement.

Allocations of Net Income

Net income is allocated between our general partner and the common unitholders in accordance with the provisions of our partnership agreement. Net income is generally allocated first to our general partner and the common unitholders in an amount equal to the net losses allocated to our general partner and the common unitholders in the current and prior tax years under the partnership agreement. The remaining net income is allocated to our general partner and the common unitholders in accordance with their respective percentage interests of the general partner and common units.

Cash Distributions

We intend to continue to make regular cash distributions to unitholders on a quarterly basis, although there is no assurance as to the future cash distributions since they are dependent upon future earnings, cash flows, capital requirements, financial condition and other factors. Our credit facility prohibits us from making cash distributions if any potential default or event of default, as defined in our credit facility, occurs or would result from the cash distribution.

Within 45 days after the end of each quarter, we will distribute all of our available cash (as defined in our partnership agreement) to our general partner and unitholders of record on the applicable record date. The amount of available cash generally is all cash on hand at the end of the quarter; less the amount of cash reserves established by our general partner to provide for the proper conduct of our business, to comply with applicable laws, any of our debt instruments, or other agreements or to provide funds for distributions to unitholders and to our general partner for any one or more of the next four quarters; plus all cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter. Working capital borrowings are generally borrowings that are made under our credit facility and in all cases are used solely for working capital purposes or to pay distributions to partners.

Our partnership agreement requires that we make distributions of available cash from operating surplus in the following manner:

- *first*, 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding common unit an amount equal to the minimum quarterly distribution for that quarter; and

- *thereafter*, cash in excess of the minimum quarterly distributions is distributed to the unitholders and the general partner based on the percentages below.

Our general partner is entitled to incentive distributions if the amount we distribute with respect to one quarter exceeds specified target levels shown below:

		Marginal Percentage Interest in Distributions	
	Total Quarterly Distributions Target Amount	Limited Partner	General Partner
Minimum quarterly distribution	$0.40	98%	2%
First target distribution	Up to $0.46	98%	2%
Second target distribution	Above $0.46, up to $0.50	85%	15%
Thereafter	Above $0.50	75%	25%

The following sets forth the distributions we paid during the years ended December 31, 2010 and 2009:

Date Paid	Period Covered	Distribution per Unit	Total Distribution
February 12, 2010	October 1, 2009 – December 31, 2009	$ 0.755	$ 20,221
May 14, 2010	January 1, 2010 – March 31, 2010	0.756	23,212
August 13, 2010	April 1, 2010 – June 30, 2010	0.757	23,248
November 12, 2010	July 1, 2010 – September 30, 2010	0.758	26,253
			$ 92,934
February 13, 2009	October 1, 2008 – December 31, 2008	$ 0.751	$ 13,814
May 15, 2009	January 1, 2009 – March 31, 2009	0.752	13,836
August 14, 2009	April 1, 2009 – June 30, 2009	0.753	17,293
November 13, 2009	July 1, 2009 – September 30, 2009	0.754	20,074
			$ 65,017

On January 26, 2011, the board of directors of EV Management declared a $0.759 per unit distribution for the fourth quarter of 2010 on all common units. The distribution was paid on February 14, 2011 to unitholders of record at the close of business on February 7, 2011. The aggregate amount of the distribution was $26.5 million.

NOTE 12. NET INCOME (LOSS) PER LIMITED PARTNER UNIT

The following sets forth the calculation of net income (loss) per limited partner unit for the years ended December 31:

	2010	2009	2008
Net income	$ 106,051	$ 1,410	$ 225,485
Less:			
Incentive distribution rights	(9,817)	(7,012)	(4,337)
General partner's 2% interest in net income	(2,121)	(28)	(4,510)
Limited partners' interest in net income (loss)	$ 94,113	$ (5,630)	$ 216,638
Weighted average limited partner units outstanding:			
Common units	27,962	16,524	12,240
Subordinated units	–	2,718	3,100
Performance units [(1)]	133	60	–
Denominator for basic net income (loss) per limited partner unit	28,095	19,302	15,340
Dilutive phantom units	67	–	–
Total	28,162	19,302	15,340
Net income (loss) per limited partner unit:			
Basic	$ 3.35	$ (0.29)	$ 14.12
Diluted	$ 3.34	$ (0.29)	$ 14.12

(1) Our earned but unvested performance units are considered to be participating securities for purposes of calculating our net income per limited partner unit, and, accordingly, are now included in the basic computation as such.

NOTE 13. RELATED PARTY TRANSACTIONS

Pursuant to our omnibus agreement with EnerVest, we paid EnerVest $8.7 million, $7.6 million and $5.5 million in the years ended December 31, 2010, 2009 and 2008, respectively, in monthly administrative fees for providing us general and administrative services. These fees are based on an allocation of charges between EnerVest and us based on the estimated use of such services by each party, and we believe that the allocation method employed by EnerVest is reasonable and reflective of the estimated level of costs we would have incurred on a standalone basis. These fees are included in general and administrative expenses in our consolidated statements of operations.

We have entered into operating agreements with EnerVest whereby a subsidiary of EnerVest acts as contract operator of the oil and natural gas wells and related gathering systems and production facilities in which we own an interest. During the years ended December 31, 2010, 2009 and 2008, we reimbursed EnerVest approximately $13.0 million, $10.3 million and $8.9 million, respectively, for direct expenses incurred in the operation of our wells and related gathering systems and production facilities and for the allocable share of the costs of EnerVest employees who performed services on our properties. As the vast majority of such expenses are charged to us on an actual basis (i.e., no mark–up or subsidy is charged or received by EnerVest), we believe that the aforementioned services were provided to us at fair and reasonable rates relative to the prevailing market and are representative of what the amounts would have been on a standalone basis. These costs are included in lease operating expenses in our consolidated statements of operations. Additionally, in its role as contract operator, this EnerVest subsidiary also collects proceeds from oil and natural gas sales and distributes them to us and other working interest owners.

In December 2010, we, along with certain institutional partnerships managed by EnerVest, acquired oil and natural gas properties in the Barnett Shale, including certain related derivatives. We acquired a 31.02% proportional interest in these properties for $295.8 million. We acquired these oil and natural gas properties from Talon Oil and Gas LLC, a portfolio company of EnCap Investments, L.P ("EnCap"). Partnerships owned by EnCap own a 23.75% interest in our general partner and Mr. Petersen, a managing director and founder of EnCap, is on our board of directors.

In September 2008, we issued 236,169 common units to EnerVest to acquire natural gas properties in West Virginia. In September 2008, we also acquired oil and natural gas properties in the San Juan Basin from institutional partnerships managed by EnerVest for $114.7 million in cash and 908,954 of our common units.

NOTE 14. OTHER SUPPLEMENTAL INFORMATION

Supplemental cash flows and non–cash transactions were as follows for the years ended December 31:

	2010	2009	2008
Supplemental cash flows information:			
Cash paid for interest	$ 8,974	$ 11,760	$ 15,822
Cash paid for income taxes	153	114	171
Non–cash transactions:			
Costs for development of oil and natural gas properties in accounts payable and accrued liabilities	6,806	1,130	3,138

NOTE 15. QUARTERLY DATA (UNAUDITED)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2010				
Revenues	$ 40,174	$ 40,907	$ 42,025	$ 48,412
Gross profit [(1)]	25,395	23,270	26,377	30,520
Net income (loss)	46,124	16,280	58,135	(14,488)
Limited partners' interest in net income (loss)	42,912	13,656	54,371	(16,826)
Net income (loss) per limited partner unit:				
Basic	$ 1.68	$ 0.50	$ 1.88	$ (0.55)
Diluted	$ 1.68	$ 0.50	$ 1.87	$ (0.55)
2009				
Revenues	$ 29,225	$ 26,988	$ 29,549	$ 36,150
Gross profit [(1)]	15,175	15,290	16,648	22,812
Net income (loss)	38,344	(31,630)	(2,833)	(2,471)
Limited partners' interest in net income (loss)	36,224	(32,693)	(4,749)	(4,412)
Net income (loss) per limited partner unit:				
Basic	$ 2.23	$ (1.93)	$ (0.23)	$ (0.19)
Diluted	$ 2.23	$ (1.93)	$ (0.23)	$ (0.19)

(1) Represents total revenues less lease operating expenses, cost of purchased natural gas and production taxes.

NOTE 16. SUPPLEMENTARY INFORMATION ON OIL AND NATURAL GAS ACTIVITIES (UNAUDITED)

Capitalized costs relating to oil and natural gas producing activities are as follows at December 31:

	2010	2009
Proved oil and natural gas properties	$ 1,493,825	$ 890,942
Unproved oil and natural gas properties	7,312	2,780
	1,501,137	893,722
Accumulated depreciation, depletion and amortization	(176,897)	(121,970)
Net capitalized costs	$ 1,324,240	$ 771,752

Costs incurred in oil and natural gas property acquisition and development activities are as follows for the years ended December 31:

	2010	2009	2008
Acquisition of oil and natural gas properties:			
Proved	$ 550,810	$ 36,530	$ 200,139
Unproved	7,003	2,619	–
Exploration costs	248	–	–
Development costs	32,478	12,263	33,940
Total	$ 590,539	$ 51,412	$ 234,079

NOTE 17. ESTIMATED PROVED OIL, NATURAL GAS AND NATURAL GAS LIQUIDS RESERVES (UNAUDITED)

Our estimated proved reserves are all located within the United States. We caution that there are many uncertainties inherent in estimating proved reserve quantities and in projecting future production rates and the timing of development expenditures. Accordingly, these estimates are expected to change as further information becomes available. Material revisions of reserve estimates may occur in the future, development and production of the oil, natural gas and natural gas liquids reserves may not occur in the periods assumed, and actual prices realized and actual costs incurred may vary significantly from those used in this estimate. The estimates of our proved reserves as of December 31, 2010, 2009 and 2008 have been prepared by Cawley, Gillespie, & Associates, Inc., independent petroleum consultants.

The following table sets forth changes in estimated proved and estimated proved developed reserves for the periods indicated.

	Oil (MBbls) (1)	Natural Gas (Mmcf) (2)	Natural Gas Liquids (MBbls) (1)	MMcfe (3)
Proved developed and undeveloped reserves:				
As of December 31, 2007	4,504	250,010	8,719	329,348
Revisions of previous estimates	(2,568)	(25,500)	(2,919)	(58,422)
Purchases of minerals in place	4,330	54,164	4,340	106,184
Extensions and discoveries	48	1,945	52	2,545
Production	(437)	(14,578)	(543)	(20,458)
As of December 31, 2008	5,877	266,041	9,649	359,197
Revisions of previous estimates	1,577	(10,984)	1,474	7,318
Purchases of minerals in place	279	15,231	90	17,443
Extensions and discoveries	186	3,478	212	5,868
Production	(514)	(16,519)	(768)	(24,210)
As of December 31, 2009	7,405	257,247	10,657	365,616
Revisions of previous estimates	558	26,464	2,080	42,302
Purchases of minerals in place	5,558	309,776	15,420	435,642
Extensions and discoveries	46	1,201	39	1,713
Production	(679)	(19,486)	(728)	(27,933)
As of December 31, 2010	12,888	575,202	27,468	817,340
Proved developed reserves:				
December 31, 2007	3,714	223,000	5,434	277,888
December 31, 2008	5,666	253,088	8,966	340,883
December 31, 2009	6,780	244,958	9,122	340,370
December 31, 2010	10,923	416,770	15,954	578,032
Proved undeveloped reserves:				
December 31, 2007	790	27,010	3,285	51,460
December 31, 2008	211	12,953	683	18,314
December 31, 2009	625	12,289	1,535	25,246
December 31, 2010	1,965	158,432	11,514	239,308

(1) Thousands of barrels.

(2) Million cubic feet.

(3) Million cubic feet equivalent; barrels are converted to Mcfe based on one barrel of oil to six Mcf of natural gas equivalent.

NOTE 18. STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL, NATURAL GAS AND NATURAL GAS LIQUIDS RESERVES (UNAUDITED)

The following tables present a standardized measure of discounted future net cash flows and changes therein relating to estimated proved oil, natural gas and natural gas liquids reserves. In computing this data, assumptions other than those required by the SEC could produce different results. Accordingly, the data should not be construed as representative of the fair market value of our estimated proved oil, natural gas and natural gas liquids reserves. The following assumptions have been made:

- Future cash inflows were based on prices used in estimating our proved oil, natural gas and natural gas liquids reserves. Future price changes were included only to the extent provided by existing contractual agreements.

- Future development and production costs were computed using year end costs assuming no change in present economic conditions.

- In accordance with our standing as a non taxable entity, no provisions for future federal income taxes were computed; however, provisions for future obligations under the Texas gross margin tax were computed.

- Future net cash flows were discounted at an annual rate of 10%.

The standardized measure of discounted future net cash flows relating to estimated proved oil, natural gas and natural gas liquids reserves is presented below for the years ended December 31:

	2010	2009	2008
Future cash inflows	$ 4,423,566	$ 1,658,755	$ 1,940,014
Future production and development costs	(1,961,304)	(909,973)	(959,623)
Future income tax expenses	(14,099)	(2,383)	(1,711)
Future net cash flows	2,448,163	746,399	978,680
10% annual discount for estimated timing of cash flows	(1,427,928)	(394,918)	(536,748)
Standardized measure of discounted future net cash flows	$ 1,020,235	$ 351,481	$ 441,932

At December 31, 2010 and 2009, as specified by the SEC, the prices for oil, natural gas and natural gas liquids used in this calculation were the average prices during 2010 determined using the price on the first day of each month, except for volumes subject to fixed price contracts. At December 31, 2008, as specified by the SEC, the prices for oil, natural gas and natural gas liquids used in this calculation were regional cash price quotes on the last day of the year except for volumes subject to fixed price contracts. The prices utilized in calculating our total estimated proved reserves at December 31, 2010, 2009 and 2008 were $79.43 per Bbl of oil and $4.376 per MMBtu of natural gas; $61.18 per Bbl of oil and $3.866 per MMBtu of natural gas; and $44.60 per Bbl of oil and $5.71 per MMBtu of natural gas, respectively. We do not include our oil and natural gas derivatives in the determination of our oil, natural gas and natural gas liquids reserves.

The principal sources of changes in the standardized measure of future net cash flows are as follows for the years ended December 31:

	2010	2009	2008
Standardized measure at beginning of period	$ 351,481	$ 441,932	$ 679,899
Sales and transfers of oil, natural gas and natural gas liquids produced, net of production costs	(104,135)	(66,588)	(131,139)
Net changes in prices and production costs	159,470	(99,677)	(408,456)
Extensions, discoveries and improved recovery, less related costs	4,523	8,235	4,543
Development costs incurred during the period	889	1,196	33,940
Revisions and other	53,126	7,061	(75,040)
Accretion of 10% timing discount	46,152	44,797	77,662
Changes in income taxes	(4,963)	(337)	2,212
Changes in estimated future development costs	(12,887)	(1,810)	19,720
Changes in timing and other	17,467	(8,021)	(11,354)
Purchase of minerals in place	509,112	24,693	249,945
Standardized measure of discounted future net cash flows	$ 1,020,235	$ 351,481	$ 441,932

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

In accordance with Exchange Act Rule 13a–15 and 15d–15, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2010 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms. Our disclosure controls and procedures include controls and procedures designed to provide reasonable assurance that information required to be disclosed in reports filed or submitted under the Exchange Act 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.

Management's Report on Internal Control Over Financial Reporting

Pursuant to Section 404 of the Sarbanes–Oxley Act of 2002, our management included a report of their assessment of the design and effectiveness of our internal controls over financial reporting as part of this Annual Report on Form 10–K for the fiscal year ended December 31, 2010. Deloitte & Touche LLP, our independent registered public accounting firm, has issued an attestation report on the effectiveness of our internal control over financial reporting. Management's report and the independent registered public accounting firm's attestation report are included in Item 8 under the caption entitled "Management's Report on Internal Control Over Financial Reporting" and "Report of Independent Registered Public Accounting Firm" and are incorporated herein by reference.

Change in Internal Controls Over Financial Reporting

There have not been any changes in our internal controls over financial reporting that occurred during the quarterly period ended December 31, 2010 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

As is the case with many publicly traded partnerships, we do not directly employ officers, directors or employees. Our operations and activities are managed by EV Management, the general partner of our general partner. EV Management is a wholly owned subsidiary of EnerVest. References to our officers, directors and employees are references to the officers, directors and employees of EV Management.

Our general partner is not elected by our unitholders and will not be subject to re–election on a regular basis in the future. Unitholders will not be entitled to elect the directors of EV Management or directly or indirectly participate in our management or operation. Our general partner is owned 71.25% by EnerVest, 23.75% by EnCap and 5.00% by EV Investors. As of December 31, 2010, EV Investors is owned 70% by EnerVest and 30% by our senior management.

Our general partner owes a fiduciary duty to our unitholders. Our general partner will be liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made expressly nonrecourse to it. Our general partner therefore may cause us to incur indebtedness or other obligations that are nonrecourse to it.

Board Leadership Structure

Our chief executive officer also serves as the chairman of our board of directors. Our board of directors has no policy regarding the separation of the positions of chief executive officer and chairman. We also do not have a lead independent director. All of our directors are appointed by EnerVest, and EnCap is entitled to appoint one director. Holders of our common units have limited voting rights on matters affecting our governance or business, subject to any unitholder rights set forth in our partnership agreement.

In selecting our independent board members, EnerVest sought candidates with experience in the energy business and in developing and implementing successful growth strategies and who have diverse expertise in areas important to our success. Directors were selected with strong professional reputations, a history of success, and who exemplify the highest standards of personal and professional integrity. Our independent directors were selected because they could be expected to constructively challenge management through their participation on our board of directors and its committees.

Board Oversight of Risk

Like all businesses, we face risks in our business activities. Many of these risks are discussed under the caption "Risk Factors" elsewhere in this annual report. Our board of directors has oversight of our risk management program, working directly with senior management. Our senior management, subject to board oversight, is responsible for ensuring that our risk management program, comprised of strategic, operational, financial, and legal risk identification and prioritization, is reflected in our policies and actions. Our senior management, subject to board oversight, is also responsible for day to day risk management and implementation of our risk management policies.

In addition, our audit committee considers our practices regarding risk assessment and risk management, reviews our contingent liabilities, reviews our oil and natural gas reserve estimation practices, as well as major legislative and regulatory developments that could affect us. Our audit committee also oversees our code of business conduct, and responses to any alleged violations of our policies made by whistleblowers. Our compensation committee reviews and attempts to mitigate risks which may result from our compensation policies, including working directly with senior management to determine whether such programs improperly encourage management to take risks relating to the business and/or whether risks arising from our compensation programs are likely to have a material adverse effect on us. Our conflicts committee reviews transactions in which we engage with affiliates of EnerVest or EnCap, and, if appropriate, approves these transactions or the manner in which any conflicts were resolved.

The board also believes that the board's role of oversight of risk management is facilitated by the leadership structure of the board. By combining the positions of Chairman of the Board and Chief Executive Officer, the board gains a valuable perspective that combines the operational expertise of a member of management with the oversight focus of a member of the board. Our board of directors believes that this division of risk management related roles among our independent directors fosters an atmosphere of significant involvement in the oversight of risk and that this shared oversight is appropriate for us.

Directors and Executive Officers

All of our executive management personnel, other than Messrs. Walker, Houser and Dwyer, are employees of EV Management and devote all of their time to our business and affairs. We estimate that Mr. Walker devotes approximately 25% of his time to our business, Mr. Houser devotes approximately 40% of his time to our business and Mr. Dwyer devotes approximately 30% of his time to our business. The officers of EV Management will manage the day–to–day affairs of our business. We also utilize a significant number of employees of EnerVest to operate our properties and provide us with certain general and administrative services. Under the omnibus agreement, we pay EnerVest a fee for its operational personnel who perform services for our benefit. During 2010, we paid EnerVest $8.7 million for general and administrative services, which fee will increase or decrease as we purchase or divest assets.

The following table shows information as of February 18, 2011 regarding members of our Board of Directors and executive officers of EV Management. Members of our Board of Directors are elected for one–year terms.

Name	Age	Position with EV Management
John B. Walker	65	Chairman and Chief Executive Officer
Mark A. Houser	49	President, Chief Operating Officer and Director
Michael E. Mercer	52	Senior Vice President and Chief Financial Officer
Ronald J. Gajdica	50	Senior Vice President of Acquisitions
Frederick Dwyer	51	Controller
Victor Burk (1) (2)	61	Director
James R. Larson (1)	61	Director
George Lindahl III (1) (2)	64	Director
Gary R. Petersen (2)	64	Director

(1) Member of the audit committee and the conflicts committee.

(2) Member of the compensation committee.

John B. Walker has served as EV Management's Chairman and Chief Executive Officer since 2006. He has been the President and CEO of EnerVest, Ltd. since its formation in 1992. Prior to that, Mr. Walker was President and Chief Operating Officer of Torch Energy Advisors Incorporated, a company which formed and managed partnerships for institutional investors in the oil and natural gas business, and Chief Executive Officer of Walker Energy Partners, a master limited partnership engaged in the exploration and production business. In his early career on Wall Street, Mr. Walker was selected by Institutional Investor as an "All American" energy analyst for six years in a row. He served the Independent Petroleum Association of America (IPAA) as Chairman from 2003 - 2005. In November 2007, he received the oil and natural gas industry's highest award, the Chief Roughneck Award. He is a member of the National Petroleum Council and All–American Wildcatters. He serves or has served on the boards of the Houston Producers' Forum, Foundation for Energy Education, Petroleum Club of Houston, and the Texas Independent Producers and Royalty Owners Association. His civic activities include having served as Chairman of the Board of Stewards of Chapelwood United Methodist Church and Chairman of the Board of Directors of the Sam Houston Area Council of the Boys Scouts of America. In 2001, he received the Silver Beaver Award and in May 2007 the Distinguished Eagle from the Boy Scouts of America. In 2004, he was named Distinguished Alumni at Texas Tech University. He holds a BBA with Honors from Texas Tech University and an MBA (with distinction) from New York University.

Mark A. Houser has served as our President since 2006. He also serves as Executive Vice President and Chief Operating Officer of EnerVest, Ltd. since 1999. Prior to that, Mr. Houser was Vice President, United States Exploration and Production, for Occidental Petroleum Corporation ("Oxy"), where he helped lead Oxy's reorganization of its domestic reserve base, including the successful $3.65 billion acquisition of the Elk Hills Naval Petroleum Reserve. In 1989 he joined Canadian Occidental Petroleum, Ltd. (now Nexen Inc.), where he held positions of increasing responsibility, including Vice President of Corporate Planning and Investor Relations in Calgary and Vice President of Exploration for CXY Energy, Canadian Oxy's United States subsidiary. Mr. Houser began his career as an engineer with Kerr–McGee Corporation. He holds a petroleum engineering degree from Texas A&M University and an MBA from Southern Methodist University. Mr. Houser serves on the board of the Texas A&M University Department of Petroleum Engineering and is a member of the Society of Petroleum Engineers.

Michael E. Mercer has served as our Senior Vice President and Chief Financial Officer since 2006. He was a consultant to EnerVest, Ltd. from 2001 to 2006. Prior to that, Mr. Mercer was an investment banker for twelve years. He was a Director in the Energy Group at Credit Suisse First Boston in Houston and a Director in the Energy Group at Salomon Smith Barney in New York and London. He holds a BBA in Petroleum Land Management from the University of Texas at Austin and an MBA from the University of Chicago Graduate School of Business.

Ronald J. Gajdica has served as our Senior Vice President of Acquisitions since 2010. Prior to that, Dr. Gajdica served as Managing Director of Scotia Waterous, a global leader in advisory services for oil and natural gas acquisitions and divestitures, where he was responsible for the Mergers, Acquisitions and Divestment technical advisory team for the U.S. and Latin America. Dr. Gajdica was employed by BHP Billiton Petroleum from 1999 – 2007 where he held the positions of Petroleum Engineering Manager, Americas Production Manager, Atlantis Deepwater Project Director and VP Global Planning and Evaluation. Prior to that, he worked at ARCO for 10 years in a variety of domestic and international assignments, including Global Director of Reservoir Studies and SEC Reserves Coordinator. He began his career at Tenneco Oil Company in 1983 spending five years as a reservoir and production engineer. Dr. Gajdica holds Bachelor (ranked first in class) and Master of Science degrees in Petroleum Engineering from Texas A&M University, and a Ph.D. in Petroleum Engineering from Stanford University.

Frederick Dwyer has served as Controller of EV Management since 2006. Mr. Dwyer joined EnerVest in September 2006 as Vice President and Corporate Controller. Prior to that, he was employed by KCS Energy, Inc., a Houston–based oil and natural gas exploration and production company, since 1986, where he held various management and supervisory positions including Vice President, Controller and Corporate Secretary. He began his career with Peat, Marwick, Mitchell & Company. Mr. Dwyer holds a Bachelor of Science degree from Manhattan College.

Victor Burk was appointed to our Board of Directors in September 2006. Since 2009, Mr. Burk has been a Managing Director for Alvarez and Marsal, a privately owned professional services firm. From 2005 to 2009, Mr. Burk was the global energy practice leader for Spencer Stuart, a privately owned executive recruiting firm. Prior to joining Spencer Stuart, Mr. Burk served as managing partner of Deloitte & Touche's global oil and natural gas group from 2002 to 2005. He began his professional career in 1972 with Arthur Andersen and served as managing partner of Arthur Andersen's global oil and natural gas group from 1989 until 2002. Mr. Burk is a current board member of the PNGS GP LLC, the general partner of PAA National Gas Storage, L.P. (NYSE: PNG). He is also a board member of the Independent Petroleum Association of America (Southeast Texas Region) and Sam Houston Area Council of the Boy Scouts of America. He holds a BBA in Accounting from Stephen F. Austin University, graduating with highest honors. Mr. Burk has over 30 years of experience in the oil and natural gas industry, with extensive experience in public accounting and consulting. Mr. Burk brings to our board wide expertise in financial and accounting matters relating to the oil and natural gas industry as well as providing leadership in complex business organizations.

James R. Larson was appointed to our Board of Directors in September 2006. Since January 1, 2006, Mr. Larson has been retired. From September 2005 until January 1, 2006, Mr. Larson served as Senior Vice President of Anadarko Petroleum Corporation. From December 2003 to September 2005, Mr. Larson served as Senior Vice President, Finance and Chief Financial Officer of Anadarko. From 2002 to 2003, Mr. Larson served as Senior Vice President, Finance of Anadarko where he oversaw treasury, investor relations, internal audits and acquisitions and divestitures. From 1995 to 2002, Mr. Larson served as Vice President and Controller of Anadarko where he was responsible for accounting, financial reporting, budgeting, forecasting and tax. Prior to that, he held various tax and financial positions within Anadarko after joining the company in 1981. Mr. Larson is a current member of the American Institute of Certified Public Accountants, Financial Executives International, Tax Executives Institute and the National Association of Corporate Directors. He holds a BBA in Business from the University of Iowa. Mr. Larson has nearly 30 years of experience in the oil and natural gas business, and has served as chief financial officer of a large independent oil and natural gas company. We believe that his knowledge of the industry and finance and accounting provide a critical resource and skill set to our board of directors.

George Lindahl III was appointed to our Board of Directors in September 2006. From 2001 to 2007, he was a Managing Partner for Sandefer Capital Partners. From 2000 to 2001 he served as Vice Chairman of Anadarko Petroleum Corporation. From 1987 to 2000, he was with Union Pacific Resources, serving as President and Chief Operating Officer from 1996 to 1999 and as Chairman, President and CEO from 1999 to 2000. He holds a BS in Geology from the University of Alabama and has completed the Advanced Management program at Harvard Business School. Mr. Lindahl has extensive geological and engineering experience, as well as leadership skills and a proven track record of successful investments in the oil and natural gas business. We believe that Mr. Lindahl's technical knowledge and experience and his leadership skills provide an important resource to our board of directors.

Gary R. Petersen was appointed to our Board of Directors in September 2006. Since 1988, Mr. Petersen has been Senior Managing Director of EnCap Investments L.P., an investment management firm which he co–founded. He had previously served as Senior Vice President of the Corporate Finance Division of the Energy Banking Group for RepublicBank Corporation from 1985 to 1988. Prior to his position at RepublicBank, he was Executive Vice President and a member of the Board of Directors of Nicklos Oil & Gas Company from 1979 to 1984. Mr. Petersen serves on the board of multiple EnCap portfolio companies and is a member of the board of directors of the general partner of Plains All American Pipeline, L.P., a publicly traded partnership engaged in the transportation and marketing of crude oil. He is a member of the Independent Petroleum Association of America, the Houston Producers' Forum and the Petroleum Club of Houston. Mr. Petersen holds a BBA and an MBA from Texas Tech University. Mr. Petersen brings to our board the expertise he has garnered from being involved in the energy sector for more than 30 years, including garnering extensive knowledge of the energy sector's various cycles, as well as the current market and industry knowledge that comes with management of approximately $7 billion of energy-related investments.

Composition of the Board of Directors

EV Management's board of directors consists of six members, one of which, Mr. Petersen, was appointed by EnCap, and the remainder of which were appointed by EnerVest.

EV Management's board of directors holds regular and special meetings at any time as may be necessary. Regular meetings may be held without notice on dates set by the board from time to time. Special meetings of the board may be called with reasonable notice to each member upon request of the chairman of the board or upon the written request of any three board members. A quorum for a regular or special meeting will exist when a majority of the members are participating in the meeting either in person or by telephone conference. Any action required or permitted to be taken at a board meeting may be taken without a meeting, without prior notice and without a vote if all of the members sign a written consent authorizing the action.

Unitholder Communications

Interested parties can communicate directly with non–management directors by mail in care of EV Energy Partners, L.P., 1001 Fannin Street, Suite 800, Houston, Texas 77002. Such communications should specify the intended recipient or recipients. Commercial solicitations or communications will not be forwarded.

Committees of the Board of Directors

EV Management's board of directors established an audit committee, a compensation committee and a conflicts committee. The charters for our audit and compensation committees are posted under the "Investor Relations" section of our website at www.evenergypartners.com. Our conflicts committee was created in our partnership agreement and does not have a charter.

Because we are a limited partnership, the listing standards of the NASDAQ do not require that we or our general partner have a majority of independent directors or a nominating or compensation committee of the board of directors. We are, however, required to have an audit committee, a majority of whose members are required to be "independent" under NASDAQ standards as described below.

Audit Committee

The audit committee is comprised of Messrs. Larson (Chairman), Burk and Lindahl, all of whom meet the independence and experience standards established by the NASDAQ and the Exchange Act. The board of directors has determined that each of Messrs. Larson, Burk and Lindahl is an "audit committee financial expert" as defined under SEC rules.

The audit committee assists the board of directors in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and corporate policies and controls. The audit committee also reviews our oil and natural gas reserve estimation processes.

The audit committee has the sole authority and responsibility to retain and terminate our independent registered public accounting firm, resolve disputes with such firm, approve all auditing services and related fees and the terms thereof, and pre–approve any non–audit services to be rendered by our independent registered public accounting firm. The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm is given unrestricted access to the audit committee and meets with the audit committee on a regularly scheduled basis. During 2010, representatives of our independent auditors attended all of our audit committee meetings. The audit committee may also engage the services of advisors and accountants as it deems advisable.

Compensation Committee

Although not required by the listing requirements of the NASDAQ, the board of directors established and maintains a compensation committee comprised of non-employee directors. The compensation committee is comprised of Messrs. Lindahl (Chairman), Burk and Petersen. The compensation committee reviews the compensation and benefits of our executive officers, establishes and reviews general policies related to our compensation and benefits and administers our long–term incentive plan (the "Plan").

Conflicts Committee

The conflicts committee is comprised of Messrs. Burk (Chairman), Larson and Lindahl, all of whom meet the independence standards established by the NASDAQ. The conflicts committee reviews specific matters that the board of directors believes may involve conflicts of interest. The conflicts committee will then determine if the conflict of interest has been resolved in accordance with our partnership agreement. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our general partner of any duties it may owe us or our unitholders.

Meetings and Other Information

During 2010, the board of directors had 10 regularly scheduled and special meetings, the audit committee had five meetings, the compensation committee had one meeting and the conflicts committee had three meetings. None of our directors attended fewer than 75% of the aggregate number of meetings of the board of directors and committees of the board on which the director served.

Our partnership agreement provides that the general partner manages and operates us and that, unlike holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business or governance. Accordingly, we do not hold annual meetings of unitholders.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires executive officers and directors of EV Management and persons who beneficially own more than 10% of a class of our equity securities registered pursuant to Section 12 of the Exchange Act to file certain reports with the SEC and the NASDAQ concerning their beneficial ownership of such securities.

Based solely on a review of the copies of reports on Forms 3, 4 and 5 and amendments thereto furnished to us and written representations from the executive officers and directors of EV Management, other than as set forth in this section, we believe that during 2010, the officers and directors of EV Management and beneficial owners of more than 10% of our equity securities registered pursuant to Section 12 were in compliance with the applicable requirements of Section 16(a). On four occasions, Mr. Houser did not timely file Form 4s during 2010 for purchases of common units made with the proceeds of distributions from units that he owns.

Code of Ethics

The corporate governance of EV Management is, in effect, the corporate governance of our partnership, subject in all cases to any specific unitholder rights contained in our partnership agreement.

EV Management has adopted a code of business conduct that applies to all officers, directors and employees of EV Management and its affiliates. A copy of our code of business conduct is available on our website at www.evenergypartners.com. We will provide a copy of our code of ethics to any person, without charge, upon request to EV Management, LLC, 1001 Fannin, Suite 800, Houston, Texas 77002, Attn: Corporate Secretary.

Reimbursement of Expenses of our General Partner

Our general partner does not receive any management fee or other compensation for its management of our partnership. Under the terms of the omnibus agreement, we pay EnerVest a fee for general and administrative services undertaken for our benefit and for our allocable portion of the premiums on insurance policies covering our assets. In addition, we reimburse EV Management for the costs of employee, officer and director compensation and benefits properly allocable to us, as well as for other expenses necessary or appropriate to the conduct of our business and properly allocable to us. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

Because our general partner is a limited partnership, its general partner, EV Management, manages our operations and activities. We do not directly employ any of the persons responsible for managing our business. Mr. Mercer and Dr. Gajdica are employees of EV Management, and we reimburse EV Management for the costs of their compensation. Mr. Mercer and Dr. Gajdica do not perform services for EnerVest or its affiliates (other than EV Management). Their compensation is approved by the compensation committee of EV Management's board of directors, which we refer to as our compensation committee.

Messrs. Walker, Houser and Dwyer are officers of EV Management and also are officers and employees of other subsidiaries of EnerVest. In these capacities, they perform services for us as well as for EnerVest and its other affiliates. Prior to 2010, Messrs. Walker, Houser and Dwyer received all of their cash salary, bonus and other compensation from EnerVest, and we did not reimburse EnerVest for these amounts (except indirectly under the omnibus agreement). Our compensation committee had no role in establishing or approving their annual salary or cash bonus. In order to compensate Messrs. Walker and Houser for the time they devote to our business and to provide our compensation committee with oversight of the portion of their annual bonuses reflecting their services to us, a portion of their cash bonus paid in 2010 was reviewed and approved by our compensation committee, and we reimbursed EnerVest for these cash bonuses. However, since the fee under the omnibus agreement had been set assuming that all of Messrs. Walker's Houser's compensation would be paid by EnerVest, the amount of the fee under the omnibus agreement for 2010 was reduced by the bonus payments to Messrs. Walker and Houser. In addition, Messrs. Walker, Houser and Dwyer will continue to participate in the Plan.

Our compensation committee discusses with EnerVest the philosophy used by EnerVest in setting the salaries and bonus compensation, but the compensation committee has no role in determining the base salary and short–term and long–term incentive compensation paid to them by EnerVest. We pay EnerVest a fee under the omnibus agreement which is based in part on the compensation paid to EnerVest employees who perform work for us, but other than the portion of Messrs. Walker's and Mr. Houser's cash bonus charged to **us,** we do not directly reimburse EnerVest for the costs of the compensation of Messrs. Walker, Houser and Dwyer and our compensation committee does not oversee their annual compensation. Awards made to Messrs. Walker, Houser and Dwyer under the Plan are determined by our compensation committee.

Our compensation committee has overall responsibility for the approval, evaluation and oversight of all of our compensation programs. The committee's primary purpose is to assist the board of directors in the discharge of its fiduciary responsibilities relating to fair and competitive compensation. The compensation committee meets in the fourth quarter of each year to review the compensation program and to determine cash compensation levels for the ensuing fiscal year and long term incentive awards for the then current fiscal year. The compensation committee may meet at other times as required.

Objectives of Our Compensation Program

Our executive compensation program is intended to align the interests of our management team with those of our unitholders by motivating our executive officers to achieve strong financial and operating results for us, which we believe closely correlate to long–term unitholder value. In addition, our program is designed to achieve the following objectives:

- attract and retain talented executive officers by providing reasonable total compensation levels competitive with that of executives holding comparable positions in similarly situated organizations;
- provide total compensation that is justified by individual performance;
- provide performance–based compensation that balances rewards for short–term and long–term results and is tied to both individual and our performance; and
- encourage the long–term commitment of our executive officers to us and our unitholders' long–term interests.

What Our Compensation Program is Designed to Reward

Our compensation program is designed to reward performance that contributes to the achievement of our business strategy on both a short–term and long–term basis. The primary long–term measure of our performance is our ability to sustain or increase our quarterly distributions to our unitholders. In addition, we reward qualities that we believe help achieve our strategy such as teamwork; individual performance in light of general economic and industry specific conditions; performance that supports our core values; resourcefulness; the ability to manage our existing assets; the ability to explore new avenues to increase oil and natural gas production and reserves; level of job responsibility; and tenure.

Benchmarking

To assist us in evaluating our compensation for 2010, our management retained Longnecker & Associates to review our proposed compensation plan for its market competitiveness and effectiveness. As part of the proposed compensation plan, our chief executive officer and president prepared an analysis of the compensation paid (based on survey data and proxy analysis) by a peer group composed of the following upstream master limited partnerships: BreitBurn Energy Partners, L.P., Legacy Reserves LP, Linn Energy, LLC, Vanguard Natural Resources and Eagle Rock Energy Partners, L.P.. Longnecker & Associates reviewed this analysis and made recommendations regarding executive compensation, director compensation and a proposed increase in total phantom unit grants. As discussed below, our management and compensation committee establish compensation for our executives based on their subjective determinations regarding the performance of our management team. Our management and compensation committee use the information regarding peer companies to check their compensation decisions for reasonableness. We target a specific percentile of our peer group only with respect to long–term incentive compensation.

Performance Metrics

With respect to bonus and long–term incentive awards, our compensation committee did not establish performance metrics for our executive officers for 2010 in order to remain flexible in our compensation practices during our first several years as a public master limited partnership. The compensation committee makes a subjective determination at the end of the fiscal year as to the appropriate compensation given their view of performance for the year.

Elements of Our Compensation Program and Why We Pay Each Element

To accomplish our objectives, we seek to offer a total direct compensation program to our executive officers that, when valued in its entirety, serves to attract, motivate and retain executives with the character, experience and professional accomplishments required for our growth and development. Our compensation program is comprised of four elements:

- base salary;
- cash bonus;
- long–term equity–based compensation; and
- benefits.

Base Salary

We pay base salary in order to recognize each executive officer's unique value and historical contributions to our success in light of salary norms in the industry and the general marketplace; to match competitors for executive talent; to provide executives with sufficient, regularly–paid income; and to reflect position and level of responsibility.

To provide stability as well as incentivize appropriately, Mr. Mercer is party to an employment agreement which sets his minimum base salary per annum. In the compensation committee’s discretion, however, his base salary may be increased based upon performance and subjective factors. For 2010, the compensation committee increased the base salary of Mr. Mercer by 4%, generally representing a cost of living increase.

Ms. MacAskie was also party to an employment agreement which set her minimum base salary per annum. In the compensation committee’s discretion, however, her base salary could be increased based upon performance and subjective factors. For 2010, the compensation committee increased Ms. MacAskie’s base salary by 4%, generally representing a cost of living increase. Ms. MacAskie resigned as Senior Vice President of Acquisitions and Divestitures effective May 15, 2010.

Dr. Gajdica joined us as Senior Vice President of Acquisitions effective June 1, 2010. His salary was determined by negotiation between our president, Mr. Houser, and Dr. Gajdica, and was approved by our compensation committee.

Cash Bonus

We include an annual cash bonus as part of our compensation program because we believe this element of compensation helps to motivate management to achieve key operational objectives by rewarding the achievement of these objectives. The annual cash bonus also allows us to be competitive from a total remuneration standpoint. Beginning in 2010, our compensation committee reviewed and approved a portion of the cash bonuses paid to Messrs. Walker and Houser. Because the fee under our omnibus agreement was established and approved assuming that EnerVest would pay all annual compensation of Messrs. Walker and Houser, we received a reduction in the 2010 omnibus fee by the amount of the bonuses we paid Mr. Walker and Mr. Houser..

Mr. Mercer's employment agreement provides that the cash bonus element of compensation will be equal to a percentage of the executive's base salary paid during each such annual period, such percentage to be established by the compensation committee in its sole discretion. Generally, we target between 50% and 75% of base salary for performance deemed by our compensation committee to be good (to generally exceed expectations) and great (to significantly exceed expectations), respectively, with the possibility of no bonus for poor performance and higher for exceptional corporate or individual performance.

In 2010, Mr. Mercer and Dr. Gajdica received cash bonuses of $230,000 and $160,000, respectively, representing 96% and 68%, respectively, of their base salaries in 2010. Mr. Mercer's bonus reflected the committee's determination that his performance for 2010 was exceptional. Dr. Gajdica's bonus was pre–determined by negotiation between our president, Mr. Houser, and Dr. Gajdica, and was approved by our compensation committee. In addition, each of Messrs. Walker and Houser were awarded cash bonuses of $150,000, representing a portion of their total annual compensation paid by us and EnerVest. The amount of bonuses were recommended to our compensation committee by Messrs. Walker and Houser based on their subjective view as to appropriate compensation levels taking into account the performance milestones discussed above and, in the case of Messrs. Walker and Houser, the amount of time they spent on our business activities. The compensation committee then determined whether to accept, reject or modify these recommendations.

The cash bonus amounts reflect the belief of our compensation committee that our executives' efforts directly affected our success in 2010, in particular, by contributing to our achievement of the following milestones:

- our quarterly distributions increased from $0.755 per unit to $0.758 per unit, the only upstream master limited partnership to increase distributions every quarter since going public;
- we ranked fourth in 2010 among upstream publicly traded master limited partnerships with respect to unit performance;
- we successfully completed in a short time frame two equity offerings totaling 7.9 million units, providing us with increased liquidity and funds available for potential acquisitions;
- our asset base increased over 130% during 2010 with over $571 million in accretive acquisitions;
- we achieved strong operating performance within production guidance; and
- the borrowing base under our credit facility was increased to $700.0 million despite deterioration in commodity prices;
- we experienced significant improvement in our ratio of net debt to PV–10 value.

As Ms. MacAskie resigned prior to year end, she did not receive a bonus in 2010. Dr. Gajdica received a cash bonus of $100,000 as an employment inducement upon his hiring in June 2010. Dr. Gajdica's cash signing bonus was based on negotiations between him and our president, Mr. Houser, and was approved by our compensation committee.

Long–term Equity–based Compensation

Long–term equity–based compensation is an element of our compensation policy because we believe it aligns executives' interests with the interests of our unitholders; rewards long–term performance; is required in order for us to be competitive from a total remuneration standpoint; encourages executive retention; and gives executives the opportunity to share in our long–term performance.

The compensation committee acts as the administrator of the Plan and performs functions that include selecting award recipients (or the manner in which such recipients will be chosen), determining the timing of grants and assigning the number of units subject to each award, fixing the time and manner in which awards are exercisable, setting exercise prices and vesting and expiration dates, and from time to time adopting rules and regulations for carrying out the purposes of our plan. For compensation decisions regarding the grant of equity compensation to executive officers, our compensation committee will consider recommendations from our chief executive officer. Typically, awards vest over multiple years, but the compensation committee maintains the discretionary authority to vest the equity grant immediately if the individual situation merits. In the event of a termination of employment upon a change of control, or upon the death, disability, retirement or termination of a grantee's employment without good reason, all outstanding equity based awards will immediately vest. We have provided for full acceleration provisions in the equity award agreements under our Plan upon a change in control because we believe that it is important to provide the named executive officers with a sense of stability in the middle of transactions that may create uncertainty regarding their future employment as well as maximize unitholder value by encouraging the named executive officers to review objectively any proposed transaction in determining whether such proposal is in the best interest of our unitholders, whether or not the executive will continue to be employed.

Except as set forth in Mr. Mercer's employment agreement, we have no set formula for granting awards to our executives or employees. In determining whether to grant awards and the amount of any awards, our compensation committee takes into consideration discretionary factors such as the individual's current and expected future performance, level of responsibility, retention considerations and the total compensation package. The compensation committee benchmarks incentive compensation against our peer group, generally targeting the 50th percentile.

Awards under the Plan may be unit options, phantom units, performance units, restricted units and deferred equity rights, or DERs, and the aggregate amount of our common units that may be awarded under the Plan is 4.5 million units. As of December 31, 2010, there are 3.2 million units available for issuance. Unless earlier terminated by us or unless all units available under the plan have been paid to participants, the Plan will terminate as of the close of business on September 20, 2016.

Although the Plan generally provides for the grant of unit options, Internal Revenue Code Section 409A and authoritative guidance thereunder provides that options can generally only be granted to employees of the entity granting the option and certain affiliates without being required to comply with Section 409A as nonqualified deferred compensation. Until further guidance is issued by the Treasury Department and Internal Revenue Service under Section 409A, we do not intend to grant unit options.

In addition, because we are a partnership, tax and accounting conventions make it more costly for us to issue additional common units or options as incentive compensation. Consequently, we have no outstanding options or restricted units and have no plans to issue options or restricted units in the future. Instead, we have issued phantom units and performance units to our executive officers. A phantom unit is the right to receive, upon satisfaction of the vesting criteria specified in the grant, a common unit or, at the discretion of our compensation committee, cash based on the average closing price of our common units for the five day trading period prior to vesting. The phantom units typically vest two to four years from the date of grant. Unlike "vesting" of an option, vesting of a phantom unit results in the delivery of a common unit or cash equivalent value as opposed to a right to exercise.

Mr. Mercer was granted 35,000 phantom units in December 2010. These phantom units vest over four years. Mr. Mercer's award was recommended to our compensation committee by our chief executive officer and president based on their subjective view as to appropriate compensation levels taking into consideration the performance milestones described above. Our compensation committee reviewed these recommendations with our chief executive officer and president. In addition, our compensation committee compared the recommended award amounts with similar awards to our peer group. In determining final grant amounts, the committee took into account Mr. Mercer's leadership roles in causing us to achieve the milestones described above and determined that performance for 2010 was exceptional. The compensation committee also took into account Longnecker & Associates' finding that Mr. Mercer's long–term incentive targets have been below the 50th percentile of the peer group in the last several years. The 2010 awards put Mr. Mercer at approximately the 75th percentile of the peer group, in order to compensate for past years where he was below the target.

Dr. Gajdica was granted 30,000 phantom units in June 2010 (inducement award upon his employment) and 30,000 phantom units in December 2010. These phantom units vest over four years. Dr. Gajdica's awards were pre–determined by negotiation between our president, Mr. Houser, and Dr. Gajdica, and were approved by our compensation committee.

Messrs. Walker and Houser made recommendations to the compensation committee for the appropriate level of awards to be made to Messrs. Walker and Houser based on their subjective view as to the appropriate compensation given the milestones achieved as discussed above. The compensation committee reviewed these recommendations and made a subjective determination as to the appropriate award levels given the achievement of such milestones. The committee also compared these award determinations to similar awards by our peer group. In determining final grant amounts, the committee took into account the executives' leadership roles in causing us to achieve the milestones described above and determined that performance for 2010 was exceptional. The committee also considered Longnecker & Associates' peer group review. Accordingly, Messrs. Walker and Houser were granted 40,000 and 37,500 phantom units, respectively, in December 2010. The 2010 awards put Mr. Walker, at just below the 50^{th} percentile and Mr. Houser at the approximate 75^{th} percentile of the peer group in order to compensate Mr. Houser based on Longnecker's finding that for the past several years where he was below the 50^{th} percentile target.

The compensation committee granted 3,500 phantom units to Mr. Dwyer in December 2010. Mr. Dwyer's long–term incentives were subjectively determined by the committee based on the recommendations of our chief executive officer and president as well as the committee's determination as to his contribution to our 2010 milestones. His awards are not compared or benchmarked against our peer group.

Benefits

We believe in a simple, straight–forward compensation program and, as such, Mr. Mercer and Dr. Gajdica are not provided unique perquisites or other personal benefits. Consistent with this strategy, no perquisites or other personal benefits have or are expected to exceed $10,000 for Mr. Mercer or Dr. Gajdica.

Through EnerVest, we provide company benefits that we believe are standard in the industry. These benefits consist of a group medical and dental insurance program for employees and their qualified dependents, group life insurance for employees and their spouses, accidental death and dismemberment coverage for employees, a company sponsored cafeteria plan and a 401(k) employee savings and investment plan. We match employee deferral amounts, including amounts deferred by named executive officers, up to a total of 6% of the employee's eligible salary, excluding annual cash bonuses, subject to certain regulatory limitations.

How Elements of Our Compensation Program are Related to Each Other

We view the various components of compensation as related but distinct and emphasize "pay for performance" with a significant portion of total compensation reflecting a risk aspect tied to long–term and short–term financial and strategic goals. Our compensation philosophy is to foster entrepreneurship at all levels of the organization by making long–term equity–based incentives, in particular unit grants, a significant component of executive compensation. We determine the appropriate level for each compensation component based in part, but not exclusively, on our view of internal equity and consistency, and other considerations we deem relevant, such as rewarding extraordinary performance.

Our compensation committee, however, has not adopted any formal or informal policies or guidelines for allocating compensation between long–term and currently paid out compensation, between cash and non–cash compensation, or among different forms of non–cash compensation.

We believe our compensation program has been instrumental in our achievement of stated objectives. Over the three year period ended December 31, 2010, our annual distribution per common unit has grown at a compound annual rate of 8% and the compound annual total rate of return for that period was approximately 14%.

Assessment of Risk

The compensation committee is aware of the need to take risk into account when making compensation decisions and periodically conducts a compensation risk analysis. In conducting this analysis, our compensation committee took into account that, by design, our compensation program for executive officers is designed to avoid excessive risk taking. In particular, our compensation committee considered the following risk–limiting characteristics of our compensation program:

- Our programs balance short–term and long–term incentives, with a substantial portion of the total compensation for our executives provided in equity and focused on long–term performance.

- Incentive plan awards are not tied to formulas that could focus executives on specific short–term outcomes.

- Members of the compensation committee approve final incentive awards in their discretion, after the review of executive and corporate performance.

- With respect to Mr. Mercer, the salary component of compensation does not encourage risk–taking because it is a fixed amount pre-negotiated under an employment agreement.

Our compensation committee has determined that there are no risks arising from our compensation policies and practices that are reasonably likely to have a material adverse affect on us.

Other Compensation Related Matters

Although we encourage our named executive officers to acquire and retain ownership in us, we do not have a policy requiring maintenance of a specified equity ownership level. As of December 31, 2010, our named executive officers beneficially owned in the aggregate approximately 4.9% of our common units (excluding any unvested equity awards). In addition, through their ownership of EnerVest and EV Investors, our executive officers also have a substantial indirect ownership interest in our general partner.

Accounting and Tax Considerations

We have structured our compensation program to comply with Internal Revenue Code Sections 162(m) and 409A. Under Section 162(m) of the Internal Revenue Code, a limitation was placed on tax deductions of any publicly–held corporation for individual compensation to certain executives of such corporation exceeding $1,000,000 in any taxable year, unless the compensation is performance–based. If an executive is entitled to nonqualified deferred compensation benefits that are subject to Section 409A, and such benefits do not comply with Section 409A, then the benefits are taxable in the first year they are not subject to a substantial risk of forfeiture. In such case, the service provider is subject to regular federal income tax, interest and an additional federal income tax of 20% of the benefit includible in income. We have no employees with non–performance based compensation paid in excess of the Internal Revenue Code Section 162(m) tax deduction limit. However, we reserve the right to use our judgment to authorize compensation payments that do not comply with the exemptions in Section 162(m) when we believe that such payments are appropriate and in the best interest of the unitholders, after taking into consideration changing business conditions or the executive’s individual performance and/or changes in specific job duties and responsibilities.

When the compensation committee makes awards under the Plan, they also review the effect the awards will have on our consolidated financial statements.

Compensation Committee Report

We have reviewed and discussed with management the compensation discussion and analysis required by Item 402(b) of Regulation S–K. Based on the review and discussion referred to above, we recommend to the board of directors that the compensation discussion and analysis be included in this Form 10–K.

Compensation Committee:
George Lindhal III (Chairman)
Victor Burk
Gary R. Petersen

Summary Compensation Table

The following table sets forth certain information with respect to compensation of our named executive officers. We reimburse EV Management for the costs of Mr. Mercer's and Dr. Gajdica's salaries and bonuses. In 2010, our compensation committee oversaw and approved a portion of the total cash bonus paid to Messrs. Walker and Houser and we will reimburse EnerVest for a portion of the cash bonus paid to Messrs. Walker and Houser. We pay EnerVest a fee under the omnibus agreement, but we do not directly reimburse EnerVest for the costs of the salaries and bonuses of Messrs. Walker, Houser and Dwyer, other than the portion of the annual cash bonuses of Messrs. Walker and Houser..

There was no compensation awarded to, earned by or paid to any of the named executive officers related to option awards or non–equity incentive compensation plans. In addition, none of the named executive officers participate in a defined benefit pension plan.

Name and Principal Position	Year	Salary	Bonus (1)	Unit Awards (2)	All Other Compensation (3)	Total
John B. Walker	2010	$ –	$ 150,000	$ 1,520,000	$ 289,991	$ 1,959,991
Chief Executive Officer	2009	–	–	1,146,000	140,468	1,286,468
	2008	–	–	398,400	115,050	513,450
Mark A. Houser	2010	–	150,000	1,425,000	266,037	1,841,037
President, Chief Operating Officer	2009	–	–	1,031,280	121,402	1,152,682
	2008	–	–	358,560	101,700	460,260
Michael E. Mercer	2010	240,000	230,000	1,330,000	244,350	2,044,350
Senior Vice President, Chief	2009	230,000	138,000	916,560	105,350	1,389,910
Financial Officer	2008	223,600	135,000	332,000	117,675	808,275
Ronald J. Gajdica (4) Senior Vice President of Acquisitions	2010	137,083	260,000	1,982,700	45,450	2,425,233
Kathryn S. MacAskie (5)	2010	107,076	–	–	122,013	229,089
Senior Vice President of	2009	230,000	138,000	916,560	105,350	1,389,910
Acquisitions and Divestitures	2008	223,600	135,000	332,000	121,425	812,025
Frederick Dwyer (6)	2010	–	–	133,000	28,998	161,998
Controller	2009	–	–	114,600	14,048	128,648

(1) Represents amounts paid in December 2010, 2009 and 2008 as bonuses for services in 2010, 2009 and 2008, respectively. Dr. Gajdica's amount for 2010 includes a signing bonus of $100,000.

(2) Reflects the aggregate grant date fair value of the phantom units granted computed in accordance with ASC Topic 718. See "Item 8. Financial Statements and Supplementary Data" for the assumptions used in estimating the grant date fair value of the phantom units granted in 2010 and the phantom units and performance units granted in 2009. The aggregate grant date fair value of the phantom units granted in 2008 was valued at the closing price of our common units on the date of grant.

(3) Represents cash distributions received on unvested phantom and performance units. Any perquisites or other personal benefits received were less than $10,000.

(4) Dr. Gajdica joined us as Senior Vice President of Acquisitions effective June 1, 2010.

(5) Ms. MacAskie resigned as Senior Vice President of Acquisitions and Divestitures effective May 15, 2010 and forfeited her unvested unit awards.

(6) Compensation for Mr. Dwyer for 2008 is not included in the table as it was less than $100,000.

Grants of Plan–Based Awards

The following table sets forth certain information with respect to grants of phantom units to our named executive officers in 2010. There were no grants of equity incentive, non–equity incentives or option awards.

Name	Grant Date	All Other Unit Awards: Number of Units	Grant Date Fair Value of Unit Awards
John B. Walker	December 2010	40,000	$ 1,520,000
Mark A. Houser	December 2010	37,500	1,425,000
Michael E. Mercer	December 2010	35,000	1,330,000
Ronald J. Gajdica	June 2010	30,000	842,700
	December 2010	30,000	1,140,000
Frederick Dwyer	December 2010	3,500	133,000

Outstanding Equity Awards at Fiscal Year End

The following table sets forth certain information with respect to outstanding equity awards at December 31, 2010. There were no option awards outstanding.

Name	Number of Units That Have Not Yet Vested	Market Value of Units That Have Not Yet Vested (1)	Equity Incentive Plan Awards: Number of Unearned Units That Have Not Yet Vested	Equity Incentive Plan Awards: Market Value of Unearned Units That Have Not Yet Vested (1)
John B. Walker	8,333(2) 52,500(3) 35,000(4) 40,000(5)	$ 5,331,455	20,000(6)	$ 785,000
Mark A. Houser	6,667(2) 50,250(3) 31,000(4) 37,500(5)	4,922,617	20,000(6)	785,000
Michael E. Mercer	5,000(2) 48,750(3) 27,000(4) 35,000(5)	4,543,188	20,000(6)	785,000
Ronald J. Gajdica	30,000(4) 30,000(5)	2,355,000	–	–
Frederick Dwyer	833(2) 5,250(3) 3,500(4) 3,500(5)	513,508	2,000(6)	78,500

(1) Based on the closing price of our common units on December 31, 2010 of $39.25.

[2] These phantom units vested in January 2011.

[3] One–third of these phantom units vested in January 2011, with one–third each vesting in January 2012 and January 2013.

[4] These phantom units vested 25% in January 2011, with 25% each vesting in January 2012, January 2013 and January 2014.

[5] These phantom units vest 25% each year beginning in January 2012.

[6] The remaining tranche of the performance units was earned in January 2011 and became phantom units. These phantom units vested 50% in January 2011, with 25% each vesting in January 2012 and January 2013.

Option Exercises and Units Vested

The following table sets forth certain information with respect to phantom units and performance units vested during 2010. There were no option awards that vested.

Name	Number of Units Acquired on Vesting (#)	Value Realized on Vesting ($)
John B. Walker	25,834	$ 785,612
Mark A. Houser	23,416	712,081
Michael E. Mercer	21,250	646,212
Ronald J. Gajdica	–	–
Kathryn S. MacAskie	21,250	646,212
Frederick Dwyer	2,584	78,579

Pension Benefits

We do not provide pension benefits for our named executive officers.

Nonqualified Deferred Compensation

We do not have a nonqualified deferred compensation plan and, as such, no compensation has been deferred by our named executive officers.

Termination of Employment and Change–in–Control Provisions

Mr. Mercer is party to an employment agreement with EV Management which provides him with post–termination benefits in a variety of circumstances. The amount of compensation payable in some cases may vary depending on the nature of the termination, whether as a result of retirement/voluntary termination, involuntary not–for–cause termination, termination following a change of control and in the event of disability or death of the executive. The discussion below describes the varying amounts payable in each of these situations. It assumes, in each case, that Mr. Mercer's termination was effective as of December 31, 2010. In presenting this disclosure, we describe amounts earned through December 31, 2010 and, in those cases where the actual amounts to be paid out can only be determined at the time of Mr. Mercer's separation from EV Management, our estimates of the amounts which would be paid out to him upon his termination.

Provisions Under the Employment Agreement

Under Mr. Mercer’s employment agreement, if his employment with EV Management and its affiliates terminates, he is entitled to unpaid salary for the full month in which the termination date occurred. However, if he is terminated for cause, he is only entitled to receive accrued but unpaid salary through the termination date. In addition, if his employment terminates, he is entitled to unpaid vacation days for that year which have accrued through the termination date, reimbursement of reasonable business expenses that were incurred but unpaid as of the termination date, and COBRA coverage as required by law. Salary and accrued vacation days are payable in cash lump sum less applicable withholdings. Business expenses are reimbursable in accordance with normal procedures.

If Mr. Mercer's employment is involuntarily terminated by EV Management (except for cause or due to the death of the executive) or if his employment is terminated due to disability or retirement, EV Management is obligated to pay as additional compensation an amount in cash equal to 104 weeks of his base salary in effect as of the termination date. Assuming he was terminated as of December 31, 2010, this amount would have been $480,000. In addition, he is entitled to continued group health plan coverage following the termination date for him and his eligible spouse and dependents for the maximum period for which such qualified beneficiaries are eligible to receive COBRA coverage. He shall not be required to pay more for COBRA coverage than officers who are then in active service for EV Management and receiving coverage under the plan. Assuming he was terminated as of December 31, 2010, this amount would have been $33,918.

In the event Mr. Mercer’s employment terminates within the 12–month period immediately following the effective date of a change in control other than by reason of death, disability or for cause, he will be entitled to receive payment of the compensation and benefits as set forth above and to become 100% fully vested in all unvested shares or units of equity compensation granted as of the effective date of the change in control. Assuming a change in control as of December 31, 2010, this amount would have been $480,000, representing 104 weeks of base salary, $5,328,188, representing vesting of unvested units and vesting of unearned units, and $33,918 representing COBRA coverage.

If the compensation is paid or benefits are provided under the employment agreement by reason of a change in control, no additional compensation will be payable or benefits provided by reason of a subsequent change in control during the term of the agreement.

“Cause” generally means:

- his conviction by a court of competent jurisdiction as to which no further appeal can be taken of a felony or entering the plea of nolo contendere to such crime by the executive;
- the commission by him of a demonstrable act of fraud, or a misappropriation of funds or property, of or upon the company or any affiliate;
- the engagement by him without approval of the board of directors or compensation committee in any material activity which directly competes with the business of the company or any affiliate or which would directly result in a material injury to the business or reputation of the company or any affiliate; or
- the material breach by him of the employment agreement, or the repeated nonperformance of his duties to the company or any affiliate (other than by reason of illness or incapacity).

In some cases, he has the opportunity to cure the breach or nonperformance before being terminated for cause.

A “change in control" generally means the occurrence of any of following events:

- a corporation, person, or group acquires, directly or indirectly, beneficial ownership of more than 50% of the equity interests in EV Management and is then entitled to vote generally in the election of the board of directors; or
- the withdrawal, removal or resignation of EV Management as the general partner of our general partner or the withdrawal, removal or resignation of our general partner as the general partner of the partnership; or
- the effective date of a merger, consolidation, or reorganization plan that is adopted by the board of directors of EV Management involving EV Management in which EV Management is not the surviving entity, or a sale of all or substantially all of our assets; or

· any other transactions or series of related transactions which have substantially the same effect as the foregoing.

"Retirement" means the termination of his employment for normal retirement at or after attaining age sixty-five provided that he has been with the company for at least five years.

Provisions Under Phantom Unit and Performance Unit Award Agreements

Both the phantom unit award agreements and performance unit award agreements provide that any unvested units will vest upon Mr. Mercer's death, disability, termination of employment other than for cause and upon a change of control. Assuming termination of employment or change of control as of December 31, 2010, the value of the awards would have been $5,328,188. If he resigns or his employment or is terminated for cause, all unvested units are forfeited. Upon vesting, the units may be paid in cash equal to the fair market value of the units on the date immediately preceding the vesting date, at the option of our general partner. The definitions of the terms such as "cause" and "change in control" in the award agreements are substantially similar to the definitions in the employment agreements.

Compensation of Directors

We use a combination of cash and unit–based inventive compensation to attract and retain qualified candidates to serve on EV Management's board. In setting director compensation, we consider the significant amount of time that directors expend in fulfilling their duties to us as well as the skill level we require of members of the board.

Directors who are not officers or employees of EV Management, EnCap or their respective affiliates receive an annual retainer of $30,000, with the chairman of the audit committee receiving an additional annual fee of $4,000 and the chairmen of the compensation committee and conflicts committee receiving an additional annual fee of $2,000. In addition, each non–employee director receives $1,000 per committee meeting attended ($500 if by phone) and is reimbursed for his out of pocket expenses in connection with attending meetings. We indemnify each director for his actions associated with being a director to the fullest extent permitted under Delaware law.

Each of the independent directors was awarded 3,500 phantom units in December 2010. Mr. Petersen, who is not an independent director because of his affiliations with EnCap, was awarded 3,000 phantom units in December 2010. These phantom units vest 25% each year beginning in January 2012**.**

The following table discloses the cash unit awards and other compensation earned, paid or awarded to each of EV Management's directors during year ended December 31, 2010:

Name [1]	Fees Earned or Paid in Cash ($)	Unit Awards [2] ($)	All Other Compensation [3] ($)	Total
Victor Burk	$ 40,000	$ 133,000	$ 13,617	$ 186,617
James R. Larson	41,000	133,000	13,617	187,617
George Lindahl III	40,000	133,000	13,617	186,617
Gary R. Petersen	–	114,000	10,966	124,966

(1) Messrs. Walker and Houser are not included in this table as they are employees of EnerVest and receive no compensation for their services as directors. Mr. Petersen is not an independent director because of his affiliations with EnCap and does not receive a cash director's fee.

(2) Reflects the aggregate grant date fair value of the phantom units granted in December 2010 computed in accordance with ASC Topic 718.

(3) Reflects the dollar amount of compensation recognized for financial statement reporting purposes for the year ended December 31, 2010 for distributions paid on the unvested phantom units.

Compensation Committee Interlocks and Insider Participation

None of our executive officers serves as a member of the board of directors or compensation committee of any entity that has one or more of its executive officers serving as a member of EV Management's board of directors or compensation committee.

None of the members of the compensation committee have served as an officer or employee of us, our general partner or its general partner. Furthermore, except for compensation arrangements discussed in this Form 10–K and as set forth in the next sentences, we have not participated in any contracts, loans, fees, awards or financial interests, direct or indirect, with any committee member, nor are we aware of any means, directly or indirectly, by which a committee member could receive a material benefit from us. We acquired properties from Talon Oil & Gas LLC, a company owned by EnCap. Mr. Petersen is an affiliate of EnCap. See "Item 13. Certain Relationships and Related Party Transactions, and Director Independence – Acquisitions with Institutional Partnerships Managed by EnerVest and from Affiliates of EnCap".

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

Security Ownership of Certain Beneficial Owners

Based solely on a review of the copies of reports on Schedules 13D and 13G and amendments thereto furnished to us, we believe that there were no beneficial owners of more than 5% of our common units as of February 18, 2011 other than set forth under "Security Ownership of Management."

Security Ownership of Management

The following table sets forth the beneficial ownership of our units as of February 18, 2011 held by:

- each member of the Board of Directors of EV Management
- each named executive officer of EV Management; and
- all directors and executive officers of EV Management as a group.

Name of Beneficial Owner [1]	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned
Officers and Directors:		
John B. Walker [2]	1,041,924	3.4%
Mark A. Houser [3]	418,652	1.4%
Michael E. Mercer	139,432	*
Ronald J. Gajdica	7,500	*
Frederick Dwyer	17,264	*
Victor Burk	7,500	*
James R. Larson	5,500	*
George Lindahl III	56,200	*
Gary R. Petersen [4]	2,000	*
All directors and executive officers as a group (9 persons)	1,695,972	5.5%

* Less than 1%

(1) Unless otherwise indicated, the address for all beneficial owners in this table is 1001 Fannin Street, Suite 800, Houston, TX 77002.

(2) Includes 884,332 common units owned by John B. and Lisa A. Walker, L.P., 10,000 common units owned by Mr. Walker's spouse and 600 common units owned by Mr. Walker's children. Mr. Walker disclaims beneficial ownership of these common units.

(3) Includes 211,520 common units owned by DSEA II, LP, a limited partnership of which Mr. Houser and his spouse manage the general partner, and 58,000 common units owned by trusts for Mr. Houser's children. Mr. Houser disclaims beneficial ownership of these common units.

(4) Includes 1,116 common units owned by EnCap Energy Capital Fund V, L.P. and 884 common units owned by EnCap Energy Capital Fund V–B, L.P. EnCap Equity Fund V GP, L.P., as the general partner of each of EnCap Energy Capital Fund V, L.P. and EnCap Energy Capital Fund V–B, L.P., EnCap Investments L.P., as the general partner of EnCap Equity Fund V GP, L.P., EnCap Investments GP, L.L.C., as the general partner of EnCap Investments L.P., RNBD GP LLC, as the sole member of EnCap Investments GP, L.L.C., and David B. Miller, Gary R. Petersen, D. Martin Phillips, and Robert L. Zorich, as the members of RNBD GP LLC may be deemed to share voting and dispositive control over the common units owned by EnCap Energy Capital Fund V, L.P. and EnCap Energy Capital Fund V–B, L.P. Each of EnCap Equity Fund V GP, L.P., EnCap Investments L.P., EnCap Investments GP, L.L.C., RNBD GP LLC, David B. Miller, Gary R. Petersen, D. Martin Phillips, and Robert L. Zorich disclaim beneficial ownership of the reported securities in excess of such entity's or person's respective pecuniary interest in the securities.

Beneficial Ownership of Our General Partner

EV Management, the general partner of our general partner, is a limited liability company wholly–owned by EnerVest, a limited partnership. Jones EnerVest Ltd., a limited partnership managed by its general partner, Jones–Tucker Corporation, whose directors are Jon Rex Jones, A.V. Jones, Jr. and Jean Jones Tucker. and members of EnerVest's executive management team, including Mr. Walker and Mr. Houser, own substantially all of the partnership interests in EnerVest. The address for Jones EnerVest Ltd. and the members of EnerVest's executive management team which own interests in EnerVest, is 1001 Fannin Street, Suite 800, Houston, Texas 77002.

Securities Authorized for Issuance under Equity Compensation Plans

In December 2010, our board of directors approved an increase in the number of common units which we may issued under the Plan from 1.5 million to 4.5 million, subject to unitholder approval, which we received in January 2011. The following table summarizes information about our equity compensation plans as of December 31, 2010:

	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	945,134	–	3,249,984
Equity compensation plans not approved by security holders	–	–	–
Total	945,134	–	3,249,984

For a description of our equity compensation plan, please see the discussion under Item 11 above.

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

Ownership in Our General Partner by the Management of EV Management and EnCap

Our general partner, EV Energy GP, is owned 71.25% by EnerVest, 23.75% by EnCap and 5% by EV Investors. Our general partner has a 2% interest in us and owns the incentive distribution rights, which entitle our general partner to a portion of the distributions we make. The distributions we will make to our general partner are described under Item 5. While EnerVest and EV Investors are under common control with us, EnCap is deemed our affiliate because EnCap has designated a director to the board of directors of EV Management.

Contracts with EnerVest and Its Affiliates

EnerVest owns all of the limited liability interests in EV Management, the general partner of our general partner. Messrs. Walker and Houser own partnership interests in EnerVest. In addition, some of the employees of EnerVest who perform services for us under the administrative services agreement and operating agreement described below are owners of EnerVest.

We have entered into agreements with EnerVest. The following is a description of these agreements.

Omnibus Agreement

In connection with our initial public offering, we entered into an omnibus agreement with EnerVest, our general partner and others that addressed the following matters:

- our obligation to pay EnerVest a monthly fee for providing us general and administrative and all other services with respect to our existing business and operations;
- our obligation to reimburse EnerVest for any insurance coverage expenses it incurs with respect to our business and operations; and
- EnerVest's obligation to indemnify us for certain liabilities and our obligation to indemnify EnerVest for certain liabilities.

Pursuant to the omnibus agreement, EnerVest performs certain centralized corporate functions for us, such as accounting, treasury, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes and engineering and senior management oversight.

Any or all of the provisions of the omnibus agreement, other than the indemnification provisions described below, will be terminable by EnerVest at its option if our general partner is removed without cause and units held by our general partner and its affiliates are not voted in favor of that removal. The omnibus agreement will also terminate in the event of a change of control of us, our general partner or the general partner of our general partner.

Under the omnibus agreement, EnerVest indemnified us for losses attributable to title defects, retained assets and liabilities (including any preclosing litigation relating to assets contributed to us) and income taxes attributable to pre–closing operations. EnerVest's maximum liability for these indemnification obligations will not exceed $1.5 million and EnerVest will not have any obligation under this indemnification until our aggregate losses exceed $200,000. We also will indemnify EnerVest for all losses attributable to the operations of the assets contributed to us after September 29, 2006, to the extent not subject to EnerVest's indemnification obligations.

During 2010, we paid EnerVest $8.7 million in monthly administrative fees under the omnibus agreement. These fees are based on an allocation of charges between EnerVest and us based on the estimated use of such services by each party, and we believe that the allocation method employed by EnerVest is reasonable and reflective of the estimated level of costs we would have incurred on a standalone basis. The initial term of the omnibus agreement expired on December 31, 2010. In December 2010, EV Management and EnerVest extended the term of the omnibus agreement through 2011.

Operating Agreements

We are party to operating agreements under which a subsidiary of EnerVest acts as contract operator of all wells in which we own an interest and are entitled to appoint the operator. As contract operator, EnerVest designs and manages the drilling and completion of our wells, and manages the day–to–day operating and maintenance activities of our wells and facilities.

Under the operating agreements, EnerVest establishes a joint account for each well in which we have an interest. The joint account is charged with all direct expenses incurred in the operation of our wells and related gathering systems and production facilities, and we are required to pay our working interest share of amounts charged to the joint account. The determination of which direct expenses can be charged to the joint account and the manner of charging direct expenses to the joint account for our wells is done in accordance with the COPAS model form of accounting procedure.

Under the COPAS model form, direct expenses include the costs of third party services performed on our properties and well, gathering and other equipment used on our properties. In addition, direct expenses will include the allocable share of the cost of the EnerVest employees who perform services on our properties. The allocation of the cost of EnerVest employees who perform services on our properties are based on time sheets maintained by EnerVest's employees. Direct expenses charged to the joint account will also include an amount determined by EnerVest to be the fair rental value of facilities owned by EnerVest and used in the operation of our properties.

During 2010, we reimbursed EnerVest approximately $13.0 million for direct expenses incurred in the operation of our wells and related gathering systems and production facilities and for the allocable share of the costs of EnerVest employees who performed services on our properties. As the vast majority of such expenses are charged to us on an actual basis (i.e., no mark–up or subsidy is charged or received by EnerVest), we believe that the aforementioned services were provided to us at fair and reasonable rates relative to the prevailing market and are representative of what the amounts would have been on a standalone basis.

Acquisitions with Institutional Partnerships Managed by EverVest and from Affiliates of EnCap

EnerVest is the general partner of institutional partnerships formed to acquire, develop and produce oil and natural gas properties. EnerVest generally has a 1% interest in the institutional partnerships that they manage, which increases to 20% following return of invested capital and a stated rate of return.

On March 30, 2010 followed by a second closing on June 29, 2010, we, along with certain institutional partnerships managed by EnerVest, acquired oil and natural gas properties in the Appalachian Basin. We acquired a 46.15% proportional interest in these properties for $145.8 million and the institutional partnerships managed by EnerVest acquired the remaining interests for $171.1 million.

On December 30, 2010, we, along with certain institutional partnerships managed by EnerVest, acquired oil and natural gas properties in the Barnett Shale, including certain related derivatives. We acquired a 31.02% proportional interest in these properties for $295.8 million and the institutional partnerships managed by EnerVest acquired the remaining interests for $657.7 million. We acquired these oil and natural gas properties from Talon Oil and Gas LLC, a portfolio company of EnCap. Partnerships owned by EnCap own a 23.75% interest in our general partner and Mr. Petersen, a managing director and founder of EnCap, is on our board of directors.

In addition to the acquisitions described above, in 2010, we, along with certain institutional partnerships managed by EnerVest, acquired oil and natural gas properties in the Appalachian Basin, the San Juan Basin and Central and East Texas for an aggregate purchase price of $7.0 million. The institutional partnerships managed by EnerVest acquired the remaining interests in these properties for $23.8 million.

The purchase price we paid for these properties was the same as the purchase price paid by these institutional partnerships, appropriately adjusted to reflect the interest acquired.

Development of the Knox Acreage

We and certain institutional partnerships managed by EnerVest own acreage in the Knox formation in the Appalachian Basin. In December 2009, we entered into an area of mutual interest ("AMI") agreement with these institutional partnerships to jointly explore and develop these properties. Under the AMI agreement, we and the institutional partnerships contributed approximately 7,760 net acres and approximately 1,740 net acres, respectively, to the AMI. We and the institutional partnerships will share 3–D seismic, development, acquisition and other costs associated with developing these properties. The revenues and costs will be shared based on the net acres contributed to the AMI, and any additional properties acquired in the area will be acquired based on such interest.

Long–Term Incentive Awards

We award phantom units under the Plan to non–executive employees of EverVest who provide services to us. These units are awarded to particular employees based on the recommendation of EnerVest's senior management. During 2010, we awarded an aggregate of 0.3 million phantom units to such employees. The market value of these units on the date of grant was approximately $12.1 million. In negotiating the fee we pay EnerVest under the omnibus agreement, the value of these phantom units is taken into account as an offset to the fee.

Director Independence

All members of the board of directors of EV Management, other than Messrs. Walker, Houser and Petersen, are independent as defined under the independence standards established by the NASDAQ. The NASDAQ does not require a listed limited partnership like us to have a majority of independent directors on the board of directors of our general partner.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The audit committee of EV Management selected Deloitte & Touche LLP, an independent registered public accounting firm, to audit our consolidated financial statements for the year ended December 31, 2010. The audit committee's charter requires the audit committee to approve in advance all audit and non–audit services to be provided by our independent registered public accounting firm. All services reported in the audit, audit–related, tax and all other fees categories below with respect to this Annual Report on Form 10–K for the year ended December 31, 2010 were approved by the audit committee.

Fees paid to Deloitte & Touche LLP are as follows:

	2010	2009
Audit fees [1]	$ 779,000	$ 834,400
Audit–related fees	198,690 [2]	161,016 [3]
Tax fees	–	–
All other fees	–	–
Total	$ 977,690	$ 995,416

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[1] Represents fees for professional services provided in connection with the audit of our annual financial statements and review of our quarterly financial statements.

[2] Represents fees for professional services provided in connection with our two public equity offerings and our current report on Form 8–K/A related the September 2010 acquisition of oil and natural gas properties in the Mid–Continent area.

[3] Represents fees for professional services provided in connection with our two public offerings, our current report on Form 8–K related to our annual report on Form 10–K/A and our SEC comment letter.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) List of Documents filed as part of this Report

(1) Financial Statements

All financial statements of the Registrant as set forth under Item 8 of this Annual Report on Form 10–K.

(2) Financial Statement Schedules

Financial statement schedules have been omitted because they are either not required, not applicable or the information required to be presented is included in our consolidated financial statements and related notes.

(3) Exhibits

The exhibits listed below are filed or furnished as part of this report:

3.1	First Amended and Restated Partnership Agreement EV Energy Partners, L.P. (Incorporated by reference from Exhibit 3.1 to EV Energy Partners, L.P.'s current report on Form 8–K filed with the SEC on October 5, 2006).
3.2	First Amended and Restated Partnership Agreement of EV Energy GP, L.P. (Incorporated by reference from Exhibit 3.2 to EV Energy Partners, L.P.'s current report on Form 8–K filed with the SEC on October 5, 2006).
3.3	Amended and Restated Limited Liability Company Agreement of EV Management, LLC. (Incorporated by reference from Exhibit 3.3 to EV Energy Partners, L.P.'s current report on Form 8–K filed with the SEC on October 5, 2006).
3.4	First Amendment dated April 15, 2008 to First Amended and Restated Partnership Agreement of EV Energy Partners, L.P., effective as of January 1, 2007 (Incorporated by reference from Exhibit 3.1 to EV Energy Partners, L.P.'s current report on Form 8–K filed with the SEC on April 18, 2008).
10.1	Omnibus Agreement, dated September 29, 2006, by and among EnerVest Management Partners, Ltd., EV Management, LLC, EV Energy GP, L.P., EV Energy Partners, L.P., and EV Properties, L.P. (Incorporated by reference from Exhibit 10.1 to EV Energy Partners, L.P.'s current report on Form 8–K filed with the SEC on October 5, 2006).
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*10.6	Employment Agreement, dated October 1, 2006, by and between EV Management, LLC and Michael E. Mercer. (Incorporated by reference from Exhibit 10.7 to EV Energy Partners, L.P.'s current report on Form 8–K filed with the SEC on October 5, 2006).
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10.9	First Amendment dated August 28, 2008 to Amended and Restated Credit Agreement (Incorporated by reference from Exhibit 10.1 to EV Energy Partners, L.P.'s current report on Form 8–K filed with the SEC on September 4, 2008).
10.10	Omnibus Agreement Extension, dated December 22, 2010, by and between EnerVest, Ltd. and EV Energy GP, L.P. (Incorporated by reference from Exhibit 10.2 to EV Energy Partners, L.P.'s current report on Form 8–K filed with the SEC on December 22, 2010).
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10.14	Underwriting Agreement dated as of February 9, 2010, among EV Energy Partners, L.P., EV Energy GP, L.P., EV Management, LLC, EV Properties, L.P., EV Properties GP, LLC, RBC Capital Markets Corporation, Citigroup Global Markets Inc., Raymond James & Associates, Inc. and Wells Fargo Securities, LLC, as representatives of the several underwriters named therein (Incorporated by reference from Exhibit 1.1 to EV Energy Partners, L.P.'s current report on Form 8–K filed with the SEC on February 12, 2010).
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10.16	Purchase and Sale Agreement by and between Petrohawk Properties, LP, KCS Resources, LLC and Hawk Field Services, LLC and EV Properties, L.P. dated August 9, 2010 (Incorporated by reference from Exhibit 2.1 to EV Energy Partners L.P.'s current report on Form 8–K filed with the SEC on August 10, 2010).
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10.19	Purchase and Sale Agreement by and between Talon Oil & Gas LLC and EnerVest Energy Institutional Fund XI-A, L.P., EnerVest Energy Institutional Fund XI-WI, L.P., EnerVest Energy Institutional Fund XII-A, L.P., EnerVest Energy Institutional Fund XII-WIB, L.P., EnerVest Energy Institutional Fund XII-WIC, L.P., EnerVest Holding, L.P. and EV Properties, L.P. dated October 25 (Incorporated by reference from Exhibit 2.1 to EV Energy Partners L.P.'s current report on Form 8–K filed with the SEC on October 29, 2010).
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+99.1	Cawley, Gillespie and Associates, Inc. Reserve Report

* Management contract or compensatory plan or arrangement

\+ Filed herewith

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

EV Energy Partners, L.P.
(Registrant)

Date: February 28, 2011

By: /s/ MICHAEL E. MERCER
Michael E. Mercer
Senior Vice President and Chief Financial Officer

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

Signature	Title	Date
/s/JOHN B. WALKER John B. Walker	Chairman and Chief Executive Officer (principal executive officer)	February 28, 2011
/s/MARK A. HOUSER Mark A. Houser	President, Chief Operating Officer and Director	February 28, 2011
/s/MICHAEL E. MERCER Michael E. Mercer	Senior Vice President and Chief Financial Officer (principal financial officer)	February 28, 2011
/s/FREDERICK DWYER Frederick Dwyer	Controller (principal accounting officer)	February 28, 2011
/s/VICTOR BURK Victor Burk	Director	February 28, 2011
/s/JAMES R. LARSON James R. Larson	Director	February 28, 2011
/s/GEORGE LINDAHL III George Lindahl, III	Director	February 28, 2011
/s/GARY R. PETERSEN Gary R. Petersen	Director	February 28, 2011

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* Management contract or compensatory plan or arrangement

\+ Filed herewith

Exhibit 21.1

EV ENERGY PARTNERS, L.P.
Subsidiaries

Subsidiary		Jurisdiction of Formation
1.	EV Properties GP, LLC	Delaware
2.	EV Properties, L.P.	Delaware
3.	EVCG GP, LLC	Delaware
4.	CGAS Properties, L.P.	Delaware
5.	EVPP GP, LLC	Delaware
6.	EnerVest Production Partners, Ltd.	Texas
7.	EnerVest Cargas, Ltd.	Texas
8.	Lower Cargas Operating Company, LLC	Louisiana

Exhibit 23.1

CAWLEY, GILLESPIE & ASSOCIATES, INC.
PETROLEUM CONSULTANTS

9601 AMBERGLEN BLVD., SUITE 117
AUSTIN, TEXAS 78729-1106
512-249-7000
FAX 512-233-2618

306 WEST SEVENTH STREET, SUITE 302
FORT WORTH, TEXAS 76102-4987
817-336-2461
FAX 817-877-3728

1000 LOUISIANA STREET, SUITE 625
HOUSTON, TEXAS 77002-5008
713-651-9944
FAX 713-651-9980

February 28, 2011

EV Energy Partners, L.P.
1001 Fannin Street, Suite 800
Houston, Texas 77002

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

As independent petroleum engineers, we hereby consent to all references to our firm included in this Form 10–K for the year ended December 31, 2010 and the Registration Statements on Form S–8 (No. 333–163686 and No. 333-140205) of EV Energy Partners, L.P. with respect to our estimates of the oil, natural gas and natural gas liquids reserves of EV Energy Partners, L.P..

Yours very truly,

/s/ W. TODD BROOKER

W. Todd Brooker, P.E.
Vice President
CAWLEY, GILLESPIE & ASSOCIATES, INC.

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333– 163686 and 333–140205 on Form S–8 of EV Energy Partners, L.P. of our report dated February 28, 2011, relating to the consolidated financial statements of EV Energy Partners, L.P. (which report expresses an unqualified opinion and includes an explanatory paragraph relating to accounting changes during 2009 for (1) oil and natural gas reserves and disclosures and (2) business combinations) and the effectiveness of EV Energy Partners L.P.'s internal control over financial reporting, appearing in this Annual Report on Form 10–K of EV Energy Partners, L.P. for the year ended December 31, 2010.

/s/DELOITTE & TOUCHE LLP
Houston, Texas
February 28, 2011

Exhibit 31.1

CERTIFICATIONS

I, John B. Walker, certify that:

1 I have reviewed this annual report on Form 10–K of EV Energy Partners, L.P.;

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 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 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: February 28, 2011

/s/ JOHN B. WALKER

John B. Walker
Chief Executive Officer of EV Management LLC,
general partner of EV Energy GP, L.P.,
general partner of EV Energy Partners, L.P.

Exhibit 31.2

CERTIFICATIONS

I, Michael E. Mercer, certify that:

1. I have reviewed this annual report on Form 10–K of EV Energy Partners, L.P.;

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 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 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: February 28, 2011

/s/ MICHAEL E. MERCER

Michael E. Mercer
Chief Financial Officer of EV Management LLC,
general partner of EV Energy GP, L.P.,
general partner of EV Energy Partners, L.P.

Exhibit 32.1

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

In connection with the accompanying report on Form 10–K for the period ended December 31, 2010 of EV Energy, L.P. (the "Partnership") and filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, John B. Walker, President and Chief Executive Officer of EV Management, LLC, the general partner of EV Energy GP, L.P., the general partner of the Partnership, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

- the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: February 28, 2011

/s/ JOHN B. WALKER
John B. Walker
Chief Executive Officer of EV Management LLC,
general partner of EV Energy GP, L.P.,
general partner of EV Energy Partners, L.P.

Exhibit 32.2

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

In connection with the accompanying report on Form 10–K for the period ended December 31, 2010 of EV Energy, L.P. (the “Partnership”) and filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Michael E. Mercer, Chief Financial Officer of EV Management, LLC, the general partner of EV Energy GP, L.P., the general partner of the Partnership, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

- the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: February 28, 2011

/s/ MICHAEL E. MERCER
Michael E. Mercer
Chief Financial Officer of EV Management LLC,
general partner of EV Energy GP, L.P.,
general partner of EV Energy Partners, L.P.

CAWLEY, GILLESPIE & ASSOCIATES, INC.

PETROLEUM CONSULTANTS

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817- 336-2461
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1000 LOUISIANA STREET, SUITE 625
HOUSTON, TEXAS 77002-5008
713-651-9944

Exhibit 99.1

January 20, 2011

EV Energy Partners, L.P.
1001 Fannin Street, Suite 800
Houston, Texas 77002

Re: Evaluation Summary
EV Energy Partners, L.P. Interests
Total Proved Reserves
As of December 31, 2010

Pursuant to the Guidelines of the Securities and Exchange Commission for Reporting Corporate Reserves and Future Net Revenue

Ladies and Gentlemen:

As requested, this report was completed on January 20, 2010 for EV Energy Partners, L.P. ("EVEP") for the purpose of public disclosure by EVEP in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. We evaluated 100% of EVEP reserves, which are made up of oil and gas properties in various fields throughout the central, southern and eastern United States. This report, with an effective date of December 31, 2010, was prepared using constant prices and costs and conforms to the guidelines of the *Securities and Exchange Commission* (SEC). The results of this evaluation are presented in the accompanying tabulations, with a composite summary of the values presented below:

		Proved Producing Developed	Proved Developed Non-Producing	Proved Developed	Proved Undeveloped	Total Proved
Net Reserves						
Oil	- Mbbl	10,467.0	455.8	10,922.8	1,965.3	12,888.1
Gas	- MMcf	385,129.6	31,640.7	416,770.3	158,431.8	575,202.0
NGL	- Mbbl	13,812.4	2,141.6	15,954.1	11,514.2	27,468.3
Revenue						
Oil	- M$	776,914.9	33,783.8	810,698.7	147,384.6	958,083.1
Gas	- M$	1,596,428.9	120,476.9	1,716,906.0	587,219.6	2,304,126.0
NGL	- M$	594,962.2	88,781.1	683,743.3	477,612.6	1,161,355.9
Net Profits	- M$	383.4	0.0	383.4	1,480.6	1,864.1
Severance Taxes	- M$	166,589.9	13,727.6	180,317.6	56,317.6	236,635.1
Ad Valorem Taxes	- M$	59,110.9	5,826.2	64,937.2	25,377.5	90,314.7
Operating Expenses	- M$	915,409.5	16,747.9	932,157.4	117,451.9	1,049,609.6
Misc. Expenses 2	- M$	4.0	0.0	4.0	0.0	4.0
Other Deductions	- M$	153,913.9	17,151.7	171,065.6	90,019.5	261,084.8
Investments	- M$	0.0	38,694.7	38,694.7	283,093.4	321,788.1
Net Cash Flows	- M$	1,672,894.3	150,893.6	1,823,788.4	638,476.1	2,462,264.5
Discounted @ 10%	**- M$**	**786,461.3**	**50,453.1**	**836,914.6**	**189,578.8**	**1,026,493.1**
(Present Worth)						

Future revenue is prior to deducting state production taxes and ad valorem taxes. Future net cash flow is after deducting these taxes, future capital costs and operating expenses, but before consideration of federal income taxes. In accordance with SEC guidelines, the future net cash flow has been discounted at an annual rate of ten percent to determine its “present worth”. The present worth is shown to indicate the effect of time on the value of money and should not be construed as being the fair market value of the properties.

The oil reserves include oil and condensate. Oil volumes are expressed in barrels (42 U.S. gallons). Gas volumes are expressed in thousands of standard cubic feet (Mcf) at contract temperature and pressure base.

Our estimates are for proved reserves only and do not include any probable or possible reserves nor have any values been attributed to interest in acreage beyond the location for which undeveloped reserves have been estimated. The Proved Developed category is the summation of the Proved Developed Producing and Proved Developed Non-Producing estimates.

<u>Presentation</u>

This report is divided into five main reserve category sections: Total Proved (“TP”), Proved Developed (“PD”), Proved Developed Producing (“PDP”), Proved Developed Non-Producing (“PDNP”) and Proved Undeveloped (“PUD”). Within each reserve category section are grand total Table I summaries for each of the main property areas and the entire reserve category. Each Table I presents composite reserve estimates and economic forecasts for the particular group of properties. Following each Table I in the TP section are Summary Plots, which are composite rate-time history-forecast curves for the corresponding group of properties. Table II “oneline” summaries are provided within the PDP, PDNP and PUD sections. The oneline summaries present estimates of ultimate recovery, gross and net reserves, ownership, revenue, expenses, investments, net income and discounted cash flow for the individual properties that make up the reserve category. The data presented in each Table I is explained in page 1 of the Appendix.

<u>Hydrocarbon Pricing</u>

The base oil and gas prices calculated for December 31, 2010 were $79.43 per barrel and $4.376 per MMBTU, respectively. As specified by the SEC, a company must use a 12-month average 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. The base oil price is based upon WTI-Cushing spot prices (EIA) during 2010 and the base gas price is based upon Henry Hub spot prices (Platt’s Gas Daily) during 2010.

The base prices were adjusted for differentials on a per-property basis, which may include local basis differentials, transportation, gas shrinkage, gas heating value (BTU content) and/or crude quality and gravity corrections. After these adjustments, the net realized prices over the life of the proved properties was estimated to be $74.339 per barrel for oil, $4.006 per MCF for gas and $42.28 per barrel for natural gas liquids. All economic factors were held constant in accordance with SEC guidelines.

<u>Economic Parameters</u>

Ownership was accepted as furnished and has not been independently confirmed. Oil and gas price differentials, gas shrinkage, ad valorem taxes, severance taxes, lease operating expenses and investments were calculated and prepared by EVEP and were thoroughly reviewed by us for accuracy, completeness and variance from prior years. Lease operating expenses were calculated based on historical lease operating statements. All economic parameters, including lease operating expenses and investments, were held constant (not escalated) throughout the life of these properties.

SEC Conformance and Regulations

The reserve classifications and the economic considerations used herein conform to the criteria of the SEC as defined in pages 3 and 4 of the Appendix. The reserves and economics are predicated on regulatory agency classifications, rules, policies, laws, taxes and royalties currently in effect except as noted herein. EVEP's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include matters relating to land tenure, drilling, production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of reserves actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

This evaluation includes 659 proved undeveloped locations, with the bulk of the projected value from 285 locations in the Talon Barnett region (Texas) and 65 locations in the Jalmat region (New Mexico). Each of these drilling locations proposed as part of EVEP's development plans conforms to the proved undeveloped standards as set forth by the SEC. In our opinion, EVEP has indicated they have every intent to complete this development plan as scheduled. Furthermore, EVEP has demonstrated that they have the proper company staffing, financial backing and prior development success to ensure the development plan will be fully executed. Reserves in the Austin Chalk region that are not scheduled to be developed within five years are delayed because of existing production through the vertical wellbores. Horizontal development through the utilization of those wellbores is scheduled to occur within the economic productive life of the vertical wells, or within a reasonable timeframe of the projected production economic limit.

Reserve Estimation Methods

The methods employed in estimating reserves are described in page 2 of the Appendix. Reserves for proved developed producing wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to offset production, both of which are considered to provide a relatively high degree of accuracy.

Non-producing reserve estimates, for both developed and undeveloped properties, were forecast using either volumetric or analogy methods, or a combination of both. These methods provide a relatively high degree of accuracy for predicting proved developed non-producing and proved undeveloped reserves for EVEP properties, due to the mature nature of their properties targeted for development and an abundance of subsurface control data. The assumptions, data, methods and procedures used herein are appropriate for the purpose served by this report.

General Discussion

The estimates and forecasts were based upon interpretations of data furnished by your office and available from our files. To some extent information from public records has been used to check and/or supplement these data. The basic engineering and geological data were subject to third party reservations and qualifications. Nothing has come to our attention, however, that would cause us to believe that we are not justified in relying on such data. All estimates represent our best judgment based on the data available at the time of preparation. Reserves estimates will generally be revised as additional geologic or engineering data become available or as economic conditions change. Moreover, estimates of reserves may increase or decrease as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. As a result, the estimates of oil and gas reserves have an intrinsic uncertainty. The reserves included in this report are therefore estimates only and should not be construed as being exact quantities. They may or may not be actually recovered, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

An on-site field inspection of the properties has not been performed. The mechanical operation or condition of the wells and their related facilities have ***not*** been examined nor have the wells been tested by Cawley, Gillespie & Associates, Inc. Possible environmental liability related to the properties has not been investigated nor considered. The cost of plugging and the salvage value of equipment at abandonment have not been included.

Cawley, Gillespie & Associates, Inc. is a Texas Registered Engineering Firm (F-693), made up of independent registered professional engineers and geologists that have provided petroleum consulting services to the oil and gas industry for over 50 years. This evaluation was supervised by W. Todd Brooker, Vice President at Cawley, Gillespie & Associates, Inc. and a State of Texas Licensed Professional Engineer (License #83462). We do not own an interest in the properties or EV Energy Partners, L.P. and are not employed on a contingent basis. We have used all methods and procedures that we consider necessary under the circumstances to prepare this report. Our work-papers and related data utilized in the preparation of these estimates are available in our office.

Yours very truly,

CAWLEY, GILLESPIE & ASSOCIATES, INC.
TEXAS REGISTERED ENGINEERING FIRM F-693

W. Todd Brooker, P. E.
Vice President

APPENDIX

Explanatory Comments for Summary Tables

HEADINGS

Table I
Description of Table Information
Identity of Interest Evaluated
Property Description – Location
Reserve Classification and Development Status
Effective Date of Evaluation

FORECAST

(Columns)

(1) (11) (21)	Calendar or Fiscal years/months commencing on effective date.
(2) (3) (4)	Gross Production (8/8th) for the years/months which are economical. These are expressed as thousands of barrels (Mbbl) and millions of cubic feet (MMcf) of gas at standard conditions. Total future production, cumulative production to effective date, and ultimate recovery at the effective date are shown following the annual/monthly forecasts.
(5) (6) (7)	Net Production accruable to evaluated interest is calculated by multiplying the revenue interest times the gross production. These values take into account changes in interest and gas shrinkage.
(8)	Average (volume weighted) gross liquid price per barrel before deducting production-severance taxes.
(9)	Average (volume weighted) gross gas price per Mcf before deducting production-severance taxes.
(10)	Average (volume weighted) gross NGL price per barrel before deducting production-severance taxes.
(12)	Revenue derived from oil sales — column (5) times column (8).
(13)	Revenue derived from gas sales — column (6) times column (9).
(14)	Revenue derived from NGL sales — column (7) times column (10).
(15)	Revenue derived from hedge positions.
(16)	Total Revenue – sum of column (12) through column (15).
(17)	Net Profits Paid – Net profits interest burden times cash flow, where cash flow is column (16) minus column (18), column (19), column (22), column (25), column (26), column (27) and column (29).
(18)	Production-Severance taxes deducted from gross oil, gas and NGL revenue.
(19)	Ad Valorem taxes.
(20)	Net MMCFE6 represents the equivalent net gas volume and is equal to column (6) plus the sum of column (5) and column (7) multiplied by 6.0.
(22)	Operating Expenses are direct operating expenses to the evaluated working interest.
(23)	Average gross wells.
(24)	Average net wells are gross wells times working interest.
(25)	Misc Expense1 are non-direct operating expenses and may include maintenance, well service, compressor, tubing, and pump repair.
(26)	Misc Expense2 are expenses not included in column (22) or column (25).
(27)	Other Deductions may include compression-gathering expenses, transportation costs and water disposal costs.
(28)	Investments, if any, include re-completions, future drilling costs, pumping units, etc. and may include either tangible or intangible or both, and the costs for plugging and the salvage value of equipment at abandonment may be shown as negative investments at end of life.
(29) (30)	Future Net Cash Flow is column (18) less the total of column (19), column (22), column (25), column (26), column (27) and column (28). The data in column (29) are accumulated in column (30). Federal income taxes have not been considered.
(31)	Cumulative Discounted Cash Flow is calculated by discounting monthly cash flows at the specified annual rates.

MISCELLANEOUS

DCF Profile	•	The cumulative cash flow discounted at six different interest rates are shown at the bottom of columns (30-31). Interest has been compounded monthly.
Life	•	The economic life of the appraised property is noted in the lower right-hand corner of the table.
Footnotes	•	Comments regarding the evaluation may be shown in the lower left-hand footnotes.
Price Deck	•	A table of oil and gas prices, price caps and escalation rates may be shown in the lower middle footnotes.
Differentials	•	Total annual price adjustments may be shown in gray font to the left of column (8), column (9) and column (10).

APPENDIX

Methods Employed in the Estimation of Reserves

The four methods customarily employed in the estimation of reserves are (1) *Production Performance*, (2) *Material Balance*, (3) *Volumetric* and (4) *Analogy*. Most estimates, although based primarily on one method, utilize other methods depending on the nature and extent of the data available and the characteristics of the reservoirs.

Basic information includes production, pressure, geological and laboratory data. However, a large variation exists in the quality, quantity and types of information available on individual properties. Operators are generally required by regulatory authorities to file monthly production reports and may be required to measure and report periodically such data as well pressures, gas-oil ratios, well tests, etc. As a general rule, an operator has complete discretion in obtaining and/or making available geological and engineering data. The resulting lack of uniformity in data renders impossible the application of identical methods to all properties, and may result in significant differences in the accuracy and reliability of estimates.

A brief discussion of each method, its basis, data requirements, applicability and generalization as to its relative degree of accuracy follows:

Production Performance. This method employs graphical analyses of production data on the premise that all factors which have controlled the performance to date will continue to control and that historical trends can be extrapolated to predict future performance. The only information required is production history. Capacity production can usually be analyzed from graphs of rates versus time or cumulative production. This procedure is referred to as "decline curve" analysis. Both capacity and restricted production can, in some cases, be analyzed from graphs of producing rate relationships of the various production components. Reserve estimates obtained by this method are generally considered to have a relatively high degree of accuracy with the degree of accuracy increasing as production history accumulates.

Material Balance. This method employs the analysis of the relationship of production and pressure performance on the premise that the reservoir volume and its initial hydrocarbon content are fixed and that this initial hydrocarbon volume and recoveries therefrom can be estimated by analyzing changes in pressure with respect to production relationships. This method requires reliable pressure and temperature data, production data, fluid analyses and knowledge of the nature of the reservoir. The material balance method is applicable to all reservoirs, but the time and expense required for its use is dependent on the nature of the reservoir and its fluids. Reserves for depletion type reservoirs can be estimated from graphs of pressures corrected for compressibility versus cumulative production, requiring only data that are usually available. Estimates for other reservoir types require extensive data and involve complex calculations most suited to computer models which make this method generally applicable only to reservoirs where there is economic justification for its use. Reserve estimates obtained by this method are generally considered to have a degree of accuracy that is directly related to the complexity of the reservoir and the quality and quantity of data available.

Volumetric. This method employs analyses of physical measurements of rock and fluid properties to calculate the volume of hydrocarbons in-place. The data required are well information sufficient to determine reservoir subsurface datum, thickness, storage volume, fluid content and location. The volumetric method is most applicable to reservoirs which are not susceptible to analysis by production performance or material balance methods. These are most commonly newly developed and/or no-pressure depleting reservoirs. The amount of hydrocarbons in-place that can be recovered is not an integral part of the volumetric calculations but is an estimate inferred by other methods and a knowledge of the nature of the reservoir. Reserve estimates obtained by this method are generally considered to have a low degree of accuracy; but the degree of accuracy can be relatively high where rock quality and subsurface control is good and the nature of the reservoir is uncomplicated.

Analogy. This method which employs experience and judgment to estimate reserves is based on observations of similar situations and includes consideration of theoretical performance. The analogy method is applicable where the data are insufficient or so inconclusive that reliable reserve estimates cannot be made by other methods. Reserve estimates obtained by this method are generally considered to have a relatively low degree of accuracy.

Much of the information used in the estimation of reserves is itself arrived at by the use of estimates. These estimates are subject to continuing change as additional information becomes available. Reserve estimates which presently appear to be correct may be found to contain substantial errors as time passes and new information is obtained about well and reservoir performance.

APPENDIX

Reserve Definitions and Classifications

The Securities and Exchange Commission, in SX Reg. 210.4-10 dated November 18, 1981, as amended on September 19, 1989 and January 1, 2010, requires adherence to the following definitions of oil and gas reserves:

"(22) **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 a 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.

"(6) **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 and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

"(31) **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 paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

"(18) **Probable reserves**. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

"(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

"(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

"(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

"(iv) See also guidelines in paragraphs (17)(iv) and (17)(vi) of this section (below).

"(17) **Possible reserves**. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

"(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

"(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

"(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

"(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

"(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

"(vi) Pursuant to paragraph (22)(iii) of this section (above), where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations."

Instruction 4 of Item 2(b) of Securities and Exchange Commission Regulation S-K was revised January 1, 2010 to state that "a registrant engaged in oil and gas producing activities shall provide the information required by Subpart 1200 of Regulation S–K." This is relevant in that Instruction 2 to paragraph (a)(2) states: "The registrant is *permitted, but not required*, to disclose probable or possible reserves pursuant to paragraphs (a)(2)(iv) through (a)(2)(vii) of this Item."

"(26) **Reserves**. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

"*Note to paragraph (26)*: Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations)."