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, 2013

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 ☐

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, 2013 based on the closing price on the NASDAQ Global Market on June 30, 2013 was $1,444,467,804.

As of February 14, 2014, the registrant had 48,572,019 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, fracture, stimulate 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. The ratio of six Mcf of natural gas to one Bbl of oil or natural gas liquids is commonly used in the oil and natural gas business and represents the approximate energy equivalency of six Mcf of natural gas to one Bbl of oil or natural gas liquids, and does not represent the sales price equivalency of natural gas to oil or natural gas liquids. Currently, the sales price of one Bbl of oil or natural gas liquids is significantly higher than the sales price of six Mcf of natural gas.

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.

Overriding royalty interest ("ORRI"). Fractional, undivided interests or rights of participation in the oil and natural gas, or in the proceeds from the sale of oil and natural gas, produced from a specified tract or tracts, which are limited in duration to the terms of an existing lease and which are not subject to any portion of the expense of development, operation or maintenance.

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.

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. 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 ("IDRs").

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

As a result of our decision to allocate resources to our midstream business, we now have two reportable segments: exploration and production and midstream. Our exploration and production segment is responsible for the acquisition, development and production of our oil and natural gas properties. Our midstream segment, which consists of our investments in Cardinal Gas Services, LLC ("Cardinal") and Utica East Ohio Midstream LLC ("UEO"), is engaged in the construction and operation of natural gas processing, natural gas liquids fractionation, connecting pipeline infrastructure and gathering systems to serve production in the Utica Shale area in Ohio. We account for our investments in Cardinal and UEO using the equity method of accounting.

As of December 31, 2013, our oil and natural gas properties were located in the Barnett Shale, the Appalachian Basin (which includes the Utica Shale), the Mid–Continent areas in Oklahoma, Texas, Arkansas, Kansas and Louisiana, the Monroe Field in Northern Louisiana, Central and East Texas (which includes the Austin Chalk area), the San Juan Basin, Michigan, and the Permian Basin. Our midstream assets are located in the Utica Shale area in Ohio.

Oil, natural gas and natural gas liquids reserve information is derived from our reserve report prepared by Cawley, Gillespie & Associates, Inc. ("Cawley Gillespie"), our independent reserve engineers. All of our proved reserves are located in the United States. The following table summarizes information about our proved reserves by geographic region as of December 31, 2013:

	Estimated Net Proved Reserves				
	Oil (MMBbls)	Natural Gas (Bcf)	Natural Gas Liquids (MMBbls)	Bcfe	PV–10 (1) ($ in millions)
Barnett Shale	1.7	529.6	40.2	781.5	$ 490.8
Appalachian Basin	4.8	80.0	0.4	111.1	195.9
Mid–Continent area	2.6	44.1	1.0	65.4	113.0
Monroe Field	–	56.2	–	56.2	20.4
Central and East Texas	2.6	24.7	2.0	52.2	112.5
San Juan Basin	0.9	31.7	2.2	50.1	42.8
Michigan	–	40.6	0.0	40.7	20.6
Permian Basin	0.5	12.8	3.1	34.4	53.4
Total	13.1	819.7	48.9	1,191.6	$ 1,049.4

(1) At December 31, 2013, our standardized measure of discounted future net cash flows was $1,039.8 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 reserves.

The table below provides a reconciliation of PV–10 to the standardized measure at December 31, 2013 (dollars in millions):

PV–10	$ 1,049.4
Future Texas gross margin taxes, discounted at 10%	(9.6)
Standardized measure	$ 1,039.8

Developments in 2013

In 2013, we invested $221.1 million in Cardinal and UEO, which included $33.3 million to increase our ownership in UEO from 8% to 21%.

In 2013, we, along with certain institutional partnerships managed by EnerVest, signed agreements to divest a portion of our Utica Shale acreage in Ohio. Through December 2013, we have closed on sales with proceeds of $44.1 million for these acres, and we expect additional closings on these acres in 2014.

In October 2013, we closed a public offering of 5.75 million common units at an offering price of $36.86 per common unit. We received net proceeds of $208.5 million, including a contribution of $4.2 million by our general partner to maintain its 2% interest in us. We used the proceeds to repay indebtedness outstanding under our credit facility.

In November 2013, we, along with certain institutional partnerships managed by EnerVest, acquired natural gas properties in the Barnett Shale. We acquired a 31% proportional interest in these properties for an aggregate purchase price of $66.0 million, subject to customary purchase price adjustments.

Development in 2014

In January 2014, we closed on the sale of our assets held for sale and received proceeds of $5.8 million.

Business Strategy

Our primary business objective is to manage our oil and natural gas properties and midstream investments 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 has allowed 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 and 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. We currently maintain derivative contracts for a significant portion of our oil, natural gas and natural gas liquids production.

  Our commodity derivatives are primarily in the form of swaps that are designed to provide a fixed price 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 interest rate swaps to minimize the effects of fluctuations in interest rates.

- *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, 2013. 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 60% of our $2.0 billion of 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 our acquisitions.

- *Pursue monetization alternatives for all or a portion of our working interest position in the Utica Shale*

  We hold a significant position of over 170,000 net working interest acres in Ohio and Pennsylvania that we believe may be prospective for the Utica Shale. In mid–2012, we initiated the process for the monetization of a portion of our working interest acres related to the Utica Shale, and in 2013, we, along with certain institutional partnerships managed by EnerVest, signed agreements to divest a portion of our Utica shale acreage in Ohio. Through December 2013, we have closed on sales with proceeds of $44.1 million for these acres, and we expect additional closings on these acres in 2014. Additional monetizations could take many forms, and we cannot at this time predict the type of transaction or transactions we may enter into or the type or amount of consideration we may receive. We may not be successful in our efforts to monetize the Utica Shale properties, it may take longer to complete a transaction than we expect, or we may decide to delay the monetization of all or a portion of the Utica Shale properties.

- *Continue capital contributions to our midstream investments and evaluate potential monetization opportunities*

  We own a 9% interest in Cardinal and a 21% interest in UEO, both of which provide midstream services to natural gas producers in the Utica Shale area in Ohio. As of December 31, 2013, we have invested $247.3 million in cash in Cardinal and UEO and plan to spend an additional $140.0 million to $160.0 million over the next two years. Both Cardinal and UEO provide a relatively stable cash flow stream based on long–term, fixed fee contracts with dedicated acreage from Chesapeake, Total and other leading producers. However, we remain focused on the acquisition, development and production of oil and natural gas properties and we will evaluate monetization alternatives for our interests in these assets as they arise.

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***

  Our properties are located in eight producing basins with an average reserve life of 19 years as of December 31, 2013. The majority of our properties have been producing for many years, resulting in predictable decline rates.

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

  We have a significant inventory of development projects in our core areas of operation. At December 31, 2013, we had 2,973 identified gross drilling locations, of which approximately 706 were proved undeveloped drilling locations and the remainder were unproved drilling locations. In 2013, we drilled a total of 174 gross (33.8 net) wells with a 98% gross success rate. Our development program is focused on lower risk drilling opportunities to maintain and increase production.

- ***Relationship with EnerVest***

  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. In addition, we believe that our relationship with EnerVest allows us to participate in much larger acquisitions than would otherwise be available to us.

- ***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 2016 at attractive average prices***

  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.

- ***Midstream investments provide relatively stable and predictable cash flows.***

  At our midstream investments, producers are charged a fixed fee for gathering, processing, transporting, fractionating, and storage services. The contracts are 15 to 20 years in duration with dedicated acreage and/or minimum volumes. These investments may enhance the stability of our cash flows and mitigate our direct exposure to commodity price risk.

Our Relationship with EnerVest

Our general partner is EV Energy GP, and its general partner is EV Management, which is a wholly owned subsidiary of 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, 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 $8.7 billion, which includes over $2.0 billion related to our acquisitions of oil and natural gas properties. EnerVest acts as an operator of over 21,800 oil and natural gas wells in 17 states.

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 oil and natural gas properties representing 93% of our proved oil and gas reserves as of December 31, 2013. The EnerVest partnerships own interests in oil and gas properties in which we own interests. The properties are primarily located in the Barnett Shale, Central and East Texas and the Appalachian Basin, and these properties represent approximately 74% of our net proved reserves at December 31, 2013. The investment strategy of the EnerVest partnerships is to typically divest their properties in three to five years, while our strategy contemplates holding such properties for a longer term. 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 agreements for certain of our EnerVest partnerships, however, provide 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 partnerships during their investment periods, EnerVest must first offer those opportunities to those EnerVest partnerships, 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.

Oil and Natural Gas Producing Activities

At December 31, 2013, our oil and natural gas properties were located in the Barnett Shale, the Appalachian Basin (which includes the Utica Shale), the Mid–Continent areas in Oklahoma, Texas, Arkansas, Kansas and Louisiana, the Monroe Field in Northern Louisiana, Central and East Texas (which includes the Austin Chalk area), the San Juan Basin, Michigan, and the Permian Basin.

Barnett Shale

We, along with certain institutional partnerships managed by EnerVest, acquired our Barnett Shale properties in December 2010, June 2011, September 2011, December 2011, February 2012, March 2012 and November 2013. The properties are primarily located in Denton, Montague, Parker, Tarrant and Wise counties in Northern Texas. Our portion of the estimated net proved reserves as of December 31, 2013 was 781.5 Bcfe, 68% of which is natural gas. During 2013, we drilled 79 gross wells, all of which were successfully completed. EnerVest operates wells representing 99% of our estimated net proved reserves in this area, and we own an average 27% working interest in 1,355 gross productive wells.

Appalachian Basin (including the Utica Shale)

We acquired our Appalachian Basin properties at our formation, and we acquired additional properties in the Appalachian Basin, primarily in West Virginia and Ohio, in December 2007, September 2008, November 2009, March 2010, June 2010, August 2011, October 2011 and August 2012. Our activities are concentrated in the Ohio and West Virginia areas of the Appalachian Basin. Our Ohio area properties are producing primarily from the Knox and Clinton formations and other Devonian age sands in 40 counties in Eastern Ohio and 8 counties in Western Pennsylvania. Our West Virginia area properties are producing primarily from the Balltown, Benson and Big Injun formations in 21 counties in North Central West Virginia. Our estimated net proved reserves as of December 31, 2013 were 111.1 Bcfe, 72% of which is natural gas. During 2013, we drilled 38 gross wells, 35 of which were successfully completed. EnerVest operates wells representing 86% of our estimated net proved reserves in this area, and we own an average 33% working interest in 8,473 gross productive wells.

Primarily through acquisitions completed in 2009 and 2010, we hold over 170,000 net working interest acres in Ohio and Pennsylvania and an approximate 2% average ORRI in approximately 880,000 gross acres in Ohio which we believe may be prospective for the Utica Shale. In addition, partnerships managed by EnerVest own acreage which may be prospective for the Utica Shale. The Utica Shale is an Ordovician-age shale that extends under much of the eastern United States. The most prospective area of the Utica Shale is in eastern Ohio, where it is located at depths ranging from 5,000 to 11,000 feet deep. The Point Pleasant carbonate member, located directly under the Utica Shale, is commonly included when referring to the Utica Shale. Horizontal drilling and hydraulic fracturing are required to allow production of hydrocarbons at economic rates. The first commercial production from the Utica Shale in eastern Ohio was achieved in 2011, and industry drilling activity is increasing.

The Utica Shale area can be divided into wet natural gas, volatile oil, black oil and dry natural gas areas. We own over 40,000 net acres in the wet natural gas area and approximately 80,000 net acres in the volatile oil area, with the remaining acreage primarily in the black oil area. Most drilling activity in the Utica Shale area has been in the wet natural gas area, but drilling activity is increasing in the dry natural gas and volatile oil areas. The current focus in the volatile oil area is on hydraulic fracturing techniques necessary to economically drill and produce in this area. We are currently seeking joint venture partners to develop and design hydraulic fracturing techniques that will allow wells in the volatile oil window to produce at economic levels.

At December 31, 2013, our estimated net proved reserves in the Utica Shale were not material to us. Exploration and development activities targeting the Utica Shale are in the early stages, and it is possible that our estimates of the acreage in Ohio that we believe is prospective for the Utica Shale may change, perhaps materially, as additional exploration and development activities are conducted in the area.

Mid–Continent Area

We acquired our Mid–Continent area properties in December 2006, August 2008, September 2008, September 2010 and November 2011. The properties are primarily located in 43 counties in Oklahoma, 22 counties in Texas, four parishes in North Louisiana, two counties in Kansas and six counties in Arkansas. Our estimated net proved reserves as of December 31, 2013 were 65.4 Bcfe, 67% of which is natural gas. During 2013, we drilled 43 gross wells, all of which were successfully completed. EnerVest operates wells representing 24% of our estimated net proved reserves in this area, and we own an average 11% working interest in 1,837 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 primarily located in two parishes in Northeast Louisiana. Our estimated net proved reserves as of December 31, 2013 were 56.2 Bcfe, 100% of which is natural gas. During 2013, we did not drill any wells. EnerVest operates wells representing 100% of our estimated net proved reserves in this area, and we own an average 100% working interest in 3,920 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 produce primarily from the Austin Chalk formation and are located in 16 counties in Central and East Texas. Our portion of the estimated net proved reserves as of December 31, 2013 was 52.2 Bcfe, 47% of which is natural gas. During 2013, we drilled 14 gross wells, 13 of which were successfully completed. EnerVest operates wells representing 97% of our estimated net proved reserves in this area, and we own an average 13% working interest 1,686 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, 2013 were 50.1 Bcfe, 63% of which is natural gas. During 2013, we did not drill any wells. EnerVest operates wells representing 94% of our estimated net proved reserves in this area, and we own an average 70% working interest in 225 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, 2013 were 40.7 Bcfe, 100% of which is natural gas. During 2013, 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 84% working interest in 376 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, 2013 were 34.4 Bcfe, 37% of which is natural gas. During 2013, we did not drill any wells. EnerVest operates wells representing 100% of our estimated net proved reserves in this area, and we own an average 97% working interest in 172 gross productive wells.

Our Oil, Natural Gas and Natural Gas Liquids Data

Our Reserves

The following table presents our estimated net proved reserves at December 31, 2013:

	Oil (MMBbls)	Natural Gas (Bcf)	Natural Gas Liquids (MMBbls)	Bcfe
Proved reserves:				
Developed	10.5	578.3	29.1	815.3
Undeveloped	2.6	241.4	19.8	376.3
Total	13.1	819.7	48.9	1,191.6

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. 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, natural gas and natural gas liquids reserve engineering is inherently a subjective process of estimating underground accumulations of oil, natural gas and natural gas liquids 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, natural gas and natural gas liquids 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.

Our Proved Undeveloped Reserves

At December 31, 2013, we had 376.3 Bcfe of proved undeveloped reserves ("PUDs") compared with 215.5 Bcfe of PUDs at December 31, 2012. The following table describes the changes in our PUDs during 2013:

	Bcfe
PUDs as of December 31, 2012	215.5
Revisions of previous estimates	(19.7)
Purchases of minerals in place	21.0
Extensions and discoveries [1]	172.0
Converted to proved developed reserves [2]	(12.5)
PUDs as of December 31, 2013	376.3

(1) Extensions and discoveries were primarily associated with development activities in the Barnett Shale (165.4 Bcfe).

(2) In 2013, we converted 6% of our PUDs at December 31, 2012 to proved developed reserves. Of this amount, 12.0 Bcfe, or 96%, related to development activities in the Barnett Shale. In 2013, we spent approximately $26.0 million related to the development of our PUDs.

We annually review all PUDs to ensure an appropriate plan for development exists. None of our PUDs as of December 31, 2013 have remained undeveloped for more than five years, except for 0.2% of our PUDs that require sidetracks of existing producing wells, in which case the development will occur when existing production ceases. We expect to convert our PUDs to proved developed reserves within five years of the date they are first booked as PUDs, except for the sidetracks mentioned above.

Internal Controls Applicable to our Reserve Estimates

Our policies and procedures regarding internal controls over the recording of our reserves is structured to objectively and accurately estimate our 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 Dr. Ronald J. Gajdica, our Senior Vice President of Acquisitions, who is also our principal engineer. Dr. Gajdica has over 30 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 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 Senior 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 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, 2013. 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. Operated wells are the wells operated by EnerVest in which we own an interest.

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	11	1,220	1,231	3	352	355
Non–operated	10	114	124	1	9	10
Appalachian Basin:						
Operated	1,089	6,467	7,556	479	2,798	3,277
Non–operated	44	873	917	6	143	149
Mid–Continent area:						
Operated	76	159	235	55	112	167
Non–operated	698	904	1,602	54	112	166
Monroe Field:						
Operated	–	3,920	3,920	–	3,883	3,883
Non–operated	–	–	–	–	–	–
Central and East Texas:						
Operated	669	707	1,376	155	100	255
Non–operated	16	294	310	–	12	12
San Juan Basin:						
Operated	32	128	160	31	123	154
Non–operated	33	32	65	3	9	12
Michigan:						
Operated	–	351	351	–	314	314
Non–operated	–	25	25	–	8	8
Permian Basin:						
Operated	11	149	160	11	146	157
Non–operated	2	10	12	–	4	4
Total (1)	2,691	15,353	18,044	798	8,125	8,923

(1) In addition, we own small royalty interests in over 1,000 wells.

Our Developed and Undeveloped Acreage

The following table sets forth information relating to our leasehold acreage as of December 31, 2013:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
Barnett Shale	157,211	40,224	22,088	5,540
Appalachian Basin	926,551	443,651	364,887	161,059
Mid–Continent area	421,238	105,911	18,243	4,358
Monroe Field [(1)]	6,147	6,147	171,463	146,784
Central and East Texas	787,042	68,902	16,972	1,802
San Juan Basin	102,591	35,574	43,857	34,342
Michigan	29,128	19,747	–	–
Permian Basin	12,216	11,495	1,000	393
Total	2,442,124	731,651	638,510	354,278

(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 acreage 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.

Production by Field

The following table sets forth our production for 2013, 2012 and 2011 from the Barnett Shale, which is the only field for which our estimated net proved reserves at December 31, 2013 attributable to the field represented 15% or more of our total estimated net proved reserves at December 31, 2013:

	Year Ended December 31,								
	2013			2012			2011		
	Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)
Barnett Shale [(1)]	100	20,083	1,472	94	18,959	1,044	12	6,812	411

(1) We acquired our interests in the Barnett Shale in December 2010, June 2011, September 2011, December 2011, February 2012, March 2012 and November 2013. Our production information includes production from the acquired interests in the Barnett Shale from the date of acquisition.

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 2013, 2012 and 2011, 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,		
	2013	2012	2011
Gross wells:			
Productive	170.0	168.0	160.0
Dry	4.0	9.0	9.0
Total	174.0	177.0	169.0
Net wells:			
Productive	32.4	35.9	29.9
Dry	1.4	3.5	2.4
Total	33.8	39.4	32.3

As of December 31, 2013, we were participating in the drilling of 27 gross (5.9 net) development wells.

We drilled 10 gross (3.6 net) exploratory wells in 2013, six of which were successfully completed as producers. We drilled 13 gross (5.6 net) exploratory wells in 2012, five of which were successfully completed as producers. We drilled 21 gross (6.9 net) exploratory wells in 2011, 14 of which were successfully completed as producers.

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, Marketing Arrangements and Delivery Commitments

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 2013, 2012 and 2011, no customer accounted for greater than 10% 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.

Information regarding our delivery commitments is contained in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Contractual Obligations" contained herein.

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.

Our Midstream Investments

In 2012, we signed limited liability agreements to become members of the Cardinal and UEO limited liability companies. We own a 9% interest in Cardinal and, through December 31, 2013, we have contributed $43.3 million in cash to Cardinal for the construction of their natural gas gathering system. We originally owned 8% of UEO, but in January 2013, we increased our ownership in UEO to 21%. Through December 31, 2013, we have contributed $204.0 million in cash to UEO for the construction of processing, fractionation and related facilities. We do not operate Cardinal or UEO. Access Midstream Partners, L.P., operator of Cardinal, and M3 Midstream LLC, operator of UEO, are responsible for the day to day decisions regarding the construction and the facilities and their operations, including the terms of their contracts. We have only limited authority to influence the operations of Cardinal and UEO.

We use the equity method of accounting for these investments, and they are treated as a business segment for financial reporting purposes. For additional information about our midstream business segment, please see "Item 8. Financial Statements and Supplementary Data" contained herein.

Cardinal

The Cardinal natural gas gathering system is a low–pressure gathering system that gathers wet natural gas from our joint venture with certain EnerVest institutional partnerships, Chesapeake Energy Corporation ("Chesapeake") and Total E&P USA, Inc. ("Total"). As of December 31, 2013, the system gathered production from over 290 wells, capable of producing over 400 MMcf per day, and we expect to have approximately 500 wells connected by the end of 2014, capable of producing approximately 700 MMcf per day.

Natural gas is gathered through fixed fee arrangements pursuant to which the fee income represents an agreed rate per unit of throughput. The revenues earned from these arrangements are directly related to the volume of natural gas that flows through the gathering system and are not directly dependent on commodity prices.

UEO

The UEO facilities gather, process and fractionate wet natural gas production from the Utica Shale area in Ohio. The joint venture between certain institutional partnerships managed by EnerVest, Chesapeake, Total and us has dedicated natural gas production from over one million net acres to the UEO plants.

The UEO facilities are composed of the Kensington processing plant located in Kensington, Ohio, the Leesville processing plant in Leesville, Ohio, the Harrison Hub facility in Scio, Ohio, a 36 mile high–pressure gathering flowline delivering wellhead natural gas to the Kensington plant, and a 37 mile natural gas liquids pipeline connecting the Harrison Hub and Kensington facilities. Natural gas processing involves the separation of raw natural gas into pipeline quality natural gas (mostly methane) and natural gas liquids. The Kensington plant currently operates two processing trains with capacity to process 400 MMcf per day. When completed, the UEO system is currently designed for four processing trains with total processing capacity of 800 MMcf per day.

The Harrison Hub facility currently operates a single fractionation train, which separates the processed natural gas liquids into their purity components (ethane, propane, normal butane isobutene and natural gasoline). Two additional fractionation trains are being constructed on the site. The Harrison Hub facility currently has fractionation capacity of 45 MBbls per day and, when completed, is expected to have 135 MBbls per day of fractionation capacity. The facility has storage capacity of approximately 870 MBbls of purity components, and is located adjacent to rail lines which provide access to all major U.S. markets for purity components.

UEO processes and fractionates wet natural gas on a fee basis under which the owners of the production are charged a fixed fee for gathering, compression, processing, transporting, fractionation and storage. Most of the contracts for processing and fractionation have a term of 15 years, and obligate the producer to deliver wet natural gas to the facilities. Title to the natural gas and purity components remains with the producer, who is responsible for arranging the purchase of the processed natural gas and purity components.

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 or disposal of the material utilized in 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;
- govern gathering, transportation and marketing of oil and natural gas and pipeline and facilities construction;
- 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. In general, the oil and natural gas industry has recently been the subject of increased legislation and regulatory attention with respect to environmental matters. The US Environmental Protection Agency (the "EPA") has identified environmental compliance by the energy extraction sector as one of its enforcement initiatives for 2014 to 2016.

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 or exempt waste or categorize some non–hazardous or exempt 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 ("PRPs") 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 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. Comparable state statutes may not provide a comparable exemption for petroleum. 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 (except for fracturing activities involving the use of diesel). Due to public concerns raised regarding potential impacts of hydraulic fracturing on groundwater quality, there have been recent developments at the federal, state, regional and local 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. The EPA released a progress report in December 2012, and final results are anticipated in 2014.

Legislation was introduced in prior sessions 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 future Congressional sessions. Also, some states and local or regional regulatory bodies have adopted, or are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances or that require disclosure of chemical in the fracturing fluids. For example, New York has imposed a de facto moratorium on hydraulic fracturing. 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. The Bureau of Land Management has proposed regulations for hydraulic fracturing on land it regulates. Further, the EPA has published draft guidance on hydraulic fracturing using diesel, has announced an initiative under the Toxic Substances Control Act to develop regulations governing the disclosure and evaluation of hydraulic fracturing chemicals and is working on regulations for wastewater created by hydraulic fracturing. 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 seek injunctive relief, requiring us to forego construction, modification or operation of certain air emission sources.

On April 17, 2012, the EPA issued final rules to subject oil and natural gas operations to regulation under the New Source Performance Standards, or NSPS, and the National Emission Standards for Hazardous Air Pollutants, or NESHAPS, programs under the CAA, and to impose new and amended requirements under both programs. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells. Before January 1, 2015, these standards require owners/operators to reduce VOC emissions from natural gas not sent to the gathering line during well completion either by flaring using a completion combustion device or by capturing the natural gas using green completions with a completion combustion device. Beginning January 1, 2015, operators must capture the natural gas and make it available for use or sale, which can be done through the use of green completions. The standards are applicable to new hydraulically fractured wells and also existing wells that are refractured. Further, the finalized regulations also establish specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, natural gas processing plants and certain other equipment. These rules may require changes to our operations, including the installation of new equipment to control emissions. We are currently evaluating the effect these rules will have on our business.

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 previously 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 GHG emission inventories and/or GHG cap and trade programs. Most of these cap and trade programs would 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. 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. We have submitted our report for 2012 and are currently working on our report for 2013.

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, natural gas and natural gas liquids 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.

Endangered Species Act

The Endangered Species Act was established to protect endangered and threatened species. Pursuant to that act, if a species is listed as threatened or endangered, restrictions may be imposed on activities that would harm the species or that would adversely affect that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We conduct operations on oil and natural gas leases that have species that are listed and species that could be listed as threatened or endangered under the act. The U.S. Fish and Wildlife Service designates the species' protected habitat as part of the effort to protect the species. A protected habitat designation or the mere presence of threatened or endangered species could result in material restrictions to our use of the land and may materially delay or prohibit land access for oil and natural gas development. It also may adversely impact the value of the affected leases.

OSHA and Other Laws and Regulation

To the extent not preempted by other applicable laws, we are subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes, where applicable. 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, where applicable, 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 state statute 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, 2013, 2012 and 2011. Additionally, we are not aware of any environmental issues or claims that will require material capital expenditures during 2014 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, local and tribal authorities. Rules and regulations affecting the oil and natural gas industry are under constant review for amendment or expansion, which could increase the regulatory burden and the potential for financial sanctions for noncompliance. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Drilling and Production

Statutes, rules and regulations affecting exploration and production undergo constant review and often are amended, expanded and reinterpreted, making difficult the prediction of future costs or the impact of regulatory compliance attributable to new laws and statutes. The regulatory burden on the oil and natural gas industry increases the cost of doing business and, consequently, affects its profitability. Our drilling and production 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, completing and operating wells;

- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells;
- notice to surface owners and other third parties; and
- produced water and disposal of waste water, drilling fluids and other liquids and solids utilized or produced in the drilling and extraction process.

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 local authorities, 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. Some states 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 their respective jurisdictions. 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, a number of states and some tribal nations have enacted surface damage statutes ("SDAs"). These laws are designed to compensate for damage caused by oil and natural gas development operations. Most SDAs contain entry notification and negotiation requirements to facilitate contact between operators and surface owners/users. Most also contain bonding requirements and require specific payments to be made in connection with 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 (the "BLM"), Bureau of Ocean Energy Management, Bureau of Safety and Environmental Enforcement, Bureau of Indian Affairs, tribal or other appropriate federal, state and/or Indian tribal agencies.

The Mineral Leasing Act of 1920 (the "Mineral Act") prohibits ownership of any direct or indirect interest in federal onshore oil and natural gas leases by a foreign citizen or a foreign entity except through equity ownership in a corporation formed under the laws of the United States or of any U.S. State or territory, and only if the laws, customs, or regulations of their country of origin or domicile do not deny similar or like privileges to citizens or entities of the United States. If these restrictions are violated, the oil and natural gas lease can be canceled in a proceeding instituted by the United States Attorney General. We qualify as an entity formed under the laws of the United States or of any U.S. State or territory. Although the regulations promulgated and administered by the BLM pursuant to the Mineral Act provide for agency designations of non–reciprocal countries, there are presently no such designations in effect. It is possible that our unitholders may be citizens of foreign countries and do not own their units in a U.S corporation or even if such interest held through a U.S. corporation, their country of citizenship may be determined to be a non–reciprocal country under the Mineral Act. In such event, any federal onshore oil and natural gas leases held by us could be subject to cancellation based on such determination.

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.

Hydraulic Fracturing

Most of our oil and natural gas properties are subject to hydraulic fracturing to economically develop the properties. The hydraulic fracturing process is integral to our drilling and completion costs in these areas and typically represent up to 60% of the total drilling/completion costs per well.

We diligently review best practices and industry standards, and comply with all regulatory requirements in the protection of these potable water sources. Protective practices include, but are not limited to, setting multiple strings of protection pipe across the potable water sources and cementing these pipes from setting depth to surface, continuously monitoring the hydraulic fracturing process in real time, and disposing of all non–commercially produced fluids in certified disposal wells at depths below the potable water sources.

In compliance with laws enacted in various states, we will disclose hydraulic fracturing data to the appropriate chemical registry. These laws generally require disclosure for each chemical ingredient that is subject to the requirements of OSHA regulations, as well as the total volume of water used in the hydraulic fracturing treatment.

There have not been any material incidents, citations or suits related to our hydraulic fracturing activities involving violations of environmental laws and regulations.

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.

Insurance

In accordance with industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. We currently have insurance policies that include coverage for control of well, general liability (includes sudden and accidental pollution), physical damage to our oil and gas natural properties, auto liability, worker's compensation and employer's liability, among other things.

Currently, we have general liability insurance coverage up to $1.0 million per occurrence, which includes sudden and accidental environmental liability coverage for the effects of pollution on third parties arising from our operations. Our insurance policies contain maximum policy limits and in most cases, deductibles that must be met prior to recovery. These insurance policies are subject to certain customary exclusions and limitations. In addition, we maintain $100.0 million in excess liability coverage, which is in addition to and triggered if the general liability per occurrence limit is reached.

We do not currently have any insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations. However, we believe our general liability and excess liability insurance policies would cover third party claims related to hydraulic fracturing operations and associated legal expenses, in accordance with, and subject to, the terms of such policies.

We re–evaluate the purchase of insurance, coverage limits and deductibles annually. Future insurance coverage for the oil and natural gas industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable and we may elect to self–insure or maintain only catastrophic coverage for certain risks in the future.

Employees

EV Management, the general partner of our general partner, has six full time employees and two executive officers who spend a significant amount of their time on our operations. At December 31, 2013, EnerVest, the sole member of EV Management, had approximately 930 full–time employees, including over 125 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 material 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 $0.771 per common unit, we will require available cash of approximately $38.7 million per quarter based on the common units and phantom units outstanding as of February 14, 2014. 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, natural gas and natural gas liquids we produce;
- the prices at which we sell our 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 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 and may be unable to service our debt obligations.

Our revenue, profitability and cash flow depend upon the prices for oil, natural gas and natural gas liquids. The prices we receive for our 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 prices have a significant impact on the value of our reserves and on our cash flows. Prices 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, natural gas and natural gas liquids;
- the amount of added production from development of unconventional natural gas reserves;
- the price and quantity of foreign imports of oil, natural gas and natural gas liquids;

- 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 prices will decrease our revenues, but may also reduce the amount of oil, natural gas or natural gas liquids 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 and service our debt obligations.

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 partnerships managed by EnerVest also own interests, and we expect to make acquisitions of properties jointly with EverVest partnerships in the future. These properties are primarily in the Barnett Shale, Central and East Texas and the Appalachian Basin, and these properties represent approximately 74% of our estimated net proved reserves as of December 31, 2013. The EnerVest partnerships generally have an investment strategy to typically divest properties in three to five years, while our strategy is to hold properties for the longer term. We own less than a majority working interest in the properties in which the EnerVest partnerships also own an interest. If the EnerVest partnerships were to sell their interest in these properties to a person not affiliated with EnerVest, our working interest would not be large enough that we could control the selection of the operator and EnerVest may lose the ability to operate the properties on our behalf. 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 in disruption in our business which could have an adverse effect on our ability to make cash distributions to our unitholders and service our debt obligations.

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 and 2012, 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.

During 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 through the over–the–counter market.

In its rulemaking under the new legislation, the CFTC has issued a final rule on position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents (with exemptions for certain *bona fide* hedging transactions); the CFTC's final rule was set aside by the U.S. District Court for the District of Columbia on September 28, 2012 and remanded to the CFTC to resolve ambiguity as to whether statutory requirements for such limits to be determined necessary and appropriate were satisfied. As a result, the rule has not yet taken effect, although the CFTC has indicated that it intends to appeal the court's decision and that it believes the Dodd–Frank Act requires it to impose position limits. The impact of such regulations upon our business is not yet clear. Certain of our hedging and trading activities and those of our counterparties may be subject to the position limits, which may reduce our ability to enter into hedging transactions.

In addition, the Act does not explicitly exempt end users (such as us) from the requirement to use cleared exchanges, rather than hedging over–the–counter, and the requirements to post margin in connection with hedging activities. While it is not possible at this time to predict when the CFTC will finalize certain other related rules and regulations, the Act and related regulations may require us to comply with margin requirements and with certain clearing and trade–execution requirements in connection with our derivative activities, although whether these requirements will apply to our business is uncertain at this time. If the regulations ultimately adopted require that we post margin for our hedging activities or require our counterparties to hold margin or maintain capital levels, the cost of which could be passed through to us, or impose other requirements that are more burdensome than current regulations, our hedging would become more expensive and we may decide to alter our hedging strategy.

The financial reform legislation may also require the counterparties to derivative instruments to spin off some of their derivative activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts reduce the availability of derivatives to protect against risks we encounter, restrict our flexibility in conducting trading and hedging activity and increase our exposure to less creditworthy counterparties. If we reduce our use of derivative contracts as a result of the new requirements, our results of operations may become more volatile and cash flows less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil, natural gas and natural gas liquids prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil, natural gas and natural gas liquids. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations, or cash flows.

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 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 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 or service our debt obligations.

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, natural gas and natural gas liquids prices and the number and attractiveness of properties for sale.

Our estimated 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 our 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, natural gas and natural gas liquids 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, natural gas and natural gas liquids 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, natural gas and natural gas liquids attributable to any particular group of properties, the classifications of reserves based on risk of recovery, and estimates of the future net cash flows. 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.

Our acquisition, development and midstream expansion 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 reserves. As part of our exploration and development operations, we have expanded, and expect to further expand, the application of horizontal drilling and multi-stage hydraulic fracture stimulation techniques. The utilization of these techniques requires substantially greater capital expenditures as compared to the drilling of a vertical well, sometimes more than three times the cost. The incremental capital expenditures are the result of greater measured depths and additional hydraulic fracture stages in horizontal wellbores. The agreements governing our midstream investments require that we make capital calls when requested by the operator of these facilities. In 2014, we expect these capital calls to be between $115.0 million and $135.0 million. Should we not make these capital calls, our ownership could be diluted or future distributions from our midstream investments could be reduced by any unfunded capital contributions.

Our capital 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 reserves;
- the amount of oil, natural gas and natural gas liquids we produce from existing wells;
- the prices at which we sell our production;
- the ability of our midstream business to obtain commitments for production to use their gathering, processing and fractionation facilities; 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, 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 for servicing our debt obligations 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 and for servicing our debt obligations.

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 and for servicing our debt obligations.

One of our growth strategies is to capitalize on opportunistic acquisitions of oil, natural gas and natural gas liquids reserves. Any future acquisition will require an assessment of recoverable reserves, title, future oil, natural gas and natural gas liquids 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 and service our debt obligations.

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

- incorrect assumptions regarding the future prices of oil, natural gas and natural gas liquids or the future operating or development costs of properties acquired;
- incorrect estimates of the 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 and service our debt obligations.

To achieve more predictable cash flows and to reduce our exposure to fluctuations in the prices of oil, natural gas and natural gas liquids, we have and may continue to enter into hedging arrangements for a significant portion of our 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 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 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 commodity 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, natural gas and natural gas liquids 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 and service our debt obligations.

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, natural gas and natural gas liquids, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for oil and natural gas properties and evaluate, bid for and purchase a greater number of properties than our financial or human resources permit. In addition, these companies may have a greater ability to continue drilling activities during periods of low 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 and service our debt obligations.

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; and
- surface spillage and surface or ground water contamination from petroleum constituents or hydraulic fracturing chemical additives.

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.

Our midstream activities are subject to all of the operating risks associated with constructing, operating and maintaining pipelines, processing and fractionation facilities, and related equipment, including the possibility of leaks, breaks and ruptures, damage due to natural hazards such as ground movement and weather, explosions, fires, personal injuries and death.

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 attorneys' 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 and service our debt obligations.

Our financial condition and results of operations may be materially 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 Safe Drinking Water Act and state or local laws and regulations related to hydraulic fracturing;
- 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 exploration, production and midstream 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 and maintaining 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 resource conservation practices and the protection of correlative rights affect our operations by limiting the quantity of oil, natural gas and natural gas liquids 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, natural gas and natural gas liquids. 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 and service our debt obligations 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, natural gas and natural gas liquids 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. We have submitted our report for 2012 and are currently working on our report for 2013.

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 previously 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, natural gas and natural gas liquids 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 effect 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 an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from dense rock formations. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in most of our drilling and completion programs. Hydraulic fracturing is typically regulated by state oil and natural gas commissions but the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act over certain hydraulic fracturing activities involving the use of diesel. In addition, in past sessions, legislation was introduced before Congress to provide for federal regulation of hydraulic fracturing under the Safe Drinking Water Act and to require disclosure of the chemicals used in the fracturing process. At the state level, some states, including Pennsylvania, Louisiana and Texas, where we operate, have adopted, and other states are considering adopting, requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. In the event that new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater; the EPA released a progress report in December 2012 and final results are expected in 2014. Moreover, the EPA has announced that it will develop effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

We are now subject to regulation under NSPS and NESHAPS programs, which could result in increased operating costs.

On April 17, 2012, the EPA issued final rules that subject oil and natural gas production, processing, transmission and storage operations to regulation under the NSPS and the NESHAP programs. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells. Before January 1, 2015, these standards require owners/operators to reduce VOC emissions from natural gas not sent to the gathering line during well completion either by flaring, using a completion combustion device, or by capturing the natural gas using green completions with a completion combustion device. Beginning January 1, 2015, operators must capture the natural gas and make it available for use or sale, which can be done through the use of green completions. The standards are applicable to newly fractured wells and also existing wells that are refractured. Further, the finalized regulations also establish specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, natural gas processing plants and certain other equipment. These rules may require changes to our operations, including the installation of new equipment to control emissions. We are currently evaluating the effect these rules will have on our business.

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, natural gas and natural gas liquids, 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 is 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, natural gas and natural gas liquids, the value of our units and our ability to pay distributions on our units and service our debt obligations.

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 production and our revenues and cash available for distribution could decline which could adversely affect our ability to make cash distributions to our unitholders and service our debt obligations.

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 and production activities in some of the areas where we operate.

Drilling and producing 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 noncash 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 and our 8% senior notes due 2019. Restrictions in our credit facility and our 8% senior notes due 2019 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 and 8% senior notes due 2019 contain 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 to our unitholders and service our debt obligations.

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.

We have limited control over operations in our midstream business.

We do not operate our UEO processing and fractionation plants or the Cardinal natural gas gathering system. We have only minority interests in the entities that own these facilities. As such, we are unable to control, and have only limited ability to influence, these businesses. The operators of these facilities may conduct the business in ways that are not as beneficial to us or our unitholders as would be the case if we operated these businesses.

If producers for our midstream investment do not increase the volumes of natural gas they provide to Cardinal and UEO gathering systems and processing facilities, our ability to increase cash flow may be adversely affected.

The ability of Cardinal and UEO to increase the throughput on their gathering systems and processing facilities will be substantially dependent on receiving increased volumes from producers. Other than the scheduled increases in the minimum volume commitments provided for in the natural gas gathering agreements with certain producers in certain geographic areas, the producers are not obligated to provide additional volumes to the systems, and they may determine in the future that drilling activities in areas outside of the current areas of operation are strategically more attractive to them. A reduction in the natural gas volumes supplied by Chesapeake, Total or other producers could result in reduced throughput on the systems and adversely impact our realized cash flows from our midstream investments.

We do not obtain independent evaluations of natural gas and natural gas liquids reserves connected to the gathering systems of our midstream investments; therefore, in the future, volumes of natural gas and natural gas liquids on our systems could be less than we currently anticipate.

We do not obtain independent evaluations of natural gas and natural gas liquids reserves connected to Cardinal and UEO. Accordingly, we do not have independent estimates of total reserves dedicated to our systems or the anticipated life of such reserves. Notwithstanding the contractual protections in certain of Cardinal and UEO's agreements, if the total reserves or estimated life of the reserves connected to our gathering systems are less than anticipated and Cardinal and UEO are unable to secure additional sources of natural gas and natural gas liquids, it could have a material adverse effect on the business of our midstream investments.

If third party pipelines or other facilities interconnected to Cardinal and UEO gathering systems or processing facilities become partially or fully unavailable, or if the volumes Cardinal and UEO gather or process do not meet the quality requirements of such pipelines or facilities, our cash flow could be adversely affected.

Cardinal and UEO natural gas gathering systems and processing facilities connect to other pipelines or facilities, the majority of which are owned by third parties. The continuing operation of such third party pipelines or facilities is not within our control. These pipelines and other facilities may become unavailable because of testing, turnarounds, line repair, reduced operating pressure, lack of operating capacity, curtailments of receipt or deliveries due to insufficient capacity or for any other reason. If any of these pipelines or facilities become unable to transport natural gas, or if the volumes that Cardinal and UEO gather, transport or process do not meet the natural gas quality requirements of such pipelines or facilities, our cash flow could be adversely affected.

Risks Inherent in an Investment in Us

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, our unitholders and the holders of our debt obligations, 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 and the holders of our debt obligations. 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 and used to service our debt obligations;
- 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 Executive Chairman of EV Management 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 Executive 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 obligations 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 and for servicing our debt obligations.

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 and for servicing our debt obligations.

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 and for servicing our debt obligations.

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.

In 2011, our general partner reset the target distribution levels and received Class B units as provided in our partnership agreement. In December 2012, the Class B units were converted into common units. Our general partner has the right to further reset the 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 14, 2014, officers and directors of EV Management owned an aggregate of 8.6% of our outstanding common. 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 and service our debt obligations.

Our partnership agreement provides that we will distribute all of our available cash to our unitholders 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, natural gas and natural gas liquids.

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 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 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 our 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 at a maximum effective rate of 0.7% on the portion of our income that is apportioned to 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 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 federal income tax purposes.

We will be considered to have terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve–month period. For 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 Medicare, 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 — Oil and Natural Gas Producing Activities 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 effect on our consolidated financial statements, and no amounts have been accrued at December 31, 2013.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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 14, 2014, based upon information received from our transfer agent and brokers and nominees, we had 213 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 2013 and 2012:

	Price Range		
	High	**Low**	**Cash Distribution per Common Unit** (1)
2013:			
First Quarter	$ 63.55	$ 50.00	$ 0.768
Second Quarter	54.81	32.65	0.769
Third Quarter	43.25	32.61	0.770
Fourth Quarter	38.94	30.53	0.771(2)
2012:			
First Quarter	$ 73.75	$ 63.25	$ 0.764
Second Quarter	70.67	43.56	0.765
Third Quarter	65.26	50.00	0.766
Fourth Quarter	66.30	55.01	0.767

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

(2) On January 31, 2014, the board of directors of EV Management declared a quarterly cash distribution for the fourth quarter of 2013 of $0.771 per common unit. The distribution was paid on February 14, 2014.

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.

Our general partner is entitled to 2% of all quarterly distributions that we make 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 the past, our general partner contributed to us an amount of cash necessary to maintain its 2% interest.

Our general partner also holds IDRs 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 the minimum quarterly distribution rate 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 12 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 in the tables in the following section.

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	$0.7615	98%	2%
First target distribution	Up to $0.875725	98%	2%
Second target distribution	Above $0.875725, up to $0.951875	85%	15%
Thereafter	Above $0.951875	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 for the periods and as of the dates indicated. The selected financial data are derived from our audited financial statements. 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.

	Year Ended December 31,				
	2013 (1)	2012 (2)	2011 (3)	2010 (4)	2009 (5)
Statement of Operations Data:					
Revenues:					
Oil, natural gas and natural gas liquids revenues	$ 310,883	$ 281,749	$ 256,370	$ 165,738	$ 114,066
Transportation and marketing–related revenues	4,429	3,731	5,470	5,780	7,846
Total revenues	315,312	285,480	261,840	171,518	121,912
Operating costs and expenses:					
Lease operating expenses	104,465	103,605	74,419	53,736	41,495
Cost of purchased natural gas	3,242	2,600	4,078	4,353	4,509
Dry hole and exploration costs	2,380	6,771	12,140	417	–
Production taxes	11,476	10,911	11,247	7,867	5,983
Asset retirement obligations accretion expense	4,925	5,116	3,914	3,153	2,035
Depreciation, depletion and amortization	113,818	113,381	74,723	55,221	52,048
General and administrative expenses	40,677	42,682	34,968	23,313	18,556
Impairment of oil and natural gas properties	85,341	34,453	11,037	–	–
Gain on sales of oil and natural gas properties	(41,309)	–	(4,017)	(40,656)	–
Total operating costs and expenses	325,015	319,519	222,509	107,404	124,626
Operating (loss) income	(9,703)	(34,039)	39,331	64,114	(2,714)
Other (expense) income, net	(66,047)	18,750	63,664	42,222	4,372
(Loss) income before income taxes and equity in (loss) income of unconsolidated affiliates	(75,750)	(15,289)	102,995	106,336	1,658
Income taxes	(133)	(1,078)	(354)	(285)	(248)
(Loss) income before equity in (loss) income of unconsolidated affiliates	(75,883)	(16,367)	102,641	106,051	1,410
Equity in (loss) income of unconsolidated affiliates	(344)	18	–	–	–
Net (loss) income	$ (76,227)	$ (16,349)	$ 102,641	$ 106,051	$ 1,410
Net (loss) income per limited partner unit:					
Basic	$ (1.76)	$ (0.38)	$ 2.71	$ 3.35	$ (0.29)
Diluted	$ (1.76)	$ (0.38)	$ 2.68	$ 3.34	$ (0.29)
Distributions declared per limited partner unit	$ 3.078	$ 3.062	$ 3.046	$ 3.03	$ 3.01
Financial Position (at end of period):					
Working capital	$ 29,435	$ 57,430	$ 122,355	$ 84,765	$ 52,825
Total assets	2,204,983	2,065,414	2,003,224	1,486,757	907,705
Long–term debt	980,297	859,218	953,023	619,000	302,000
Owners' equity	1,071,933	1,059,824	920,039	773,947	547,431

(1) Includes the results of the acquisitions of oil and natural gas properties in the Barnett Shale in November 2013.

(2) Includes the results of the acquisitions of oil and natural gas properties in the Barnett Shale in February 2012 and March 2012.

(3) Includes the results of (i) the acquisition of oil and natural gas properties in the Barnett Shale in June 2011, September 2011 and December 2011, (ii) the acquisition of oil and natural gas properties in the Appalachian Basin in August 2011 and October 2011 and (iii) the acquisition of oil and natural gas properties in the Mid–Continent area in November 2011.

(4) 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.

(5) Includes the results of the acquisition of oil and natural gas properties in Central and East Texas in July 2009 and September 2009 and the acquisition of oil and natural gas properties in the Appalachian Basin in November 2009.

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. 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 a result of our decision to allocate resources to our midstream business, we now have two reportable segments: exploration and production and midstream. Our exploration and production segment is responsible for the acquisition, development and production of our oil and natural gas properties. Our midstream segment, which consists of our investments in Cardinal and UEO, is engaged in the construction and operation of natural gas processing, natural gas liquids fractionation, connecting pipeline infrastructure and gathering systems to serve production in the Utica Shale area in Ohio. We account for our investments in Cardinal and UEO using the equity method of accounting.

As of December 31, 2013, our oil and natural gas properties were located in the Barnett Shale, the Appalachian Basin (which includes the Utica Shale), the Mid-Continent area in Oklahoma, Texas, Arkansas, Kansas and Louisiana, the Monroe Field in Northern Louisiana, Central and East Texas (which includes the Austin Chalk area), the San Juan Basin, Michigan, and the Permian Basin. As of December 31, 2013, we had estimated net proved reserves of 13.1 MMBbls of oil, 819.7 Bcf of natural gas and 48.9 MMBbls of natural gas liquids, or 1,191.6 Bcfe, and a standardized measure of $1,039.8 million.

Developments in 2013

In 2013, we invested $221.1 million in Cardinal and UEO, which included $33.3 million to increase our ownership in UEO from 8% to 21%.

In 2013, we, along with certain institutional partnerships managed by EnerVest, signed agreements to divest a portion of our Utica Shale acreage in Ohio. Through December 2013, we have closed on sales with proceeds of $44.1 million for these acres, and we expect additional closings on these acres in 2014.

In October 2013, we closed a public offering of 5.75 million common units at an offering price of $36.86 per common unit. We received net proceeds of $208.5 million, including a contribution of $4.2 million by our general partner to maintain its 2% interest in us. We used the proceeds to repay indebtedness outstanding under our credit facility.

In November 2013, we, along with certain institutional partnerships managed by EnerVest, acquired natural gas properties in the Barnett Shale. We acquired a 31% proportional interest in these properties for an aggregate purchase price of $66.0 million, subject to customary purchase price adjustments.

Development in 2014

In January 2014, we closed on the sale of our assets held for sale and received proceeds of $5.8 million.

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 distributions that we may receive from our interests in Cardinal and UEO;
- the amount of oil, natural gas liquids and natural gas we produce; and
- the level of our operating and administrative costs.

Oil, natural gas and natural gas liquids 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 and natural gas liquids 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 and natural gas liquids, storage levels of natural gas and natural gas liquids and the availability and accessibility of natural gas deposits in North America.

In order to mitigate the impact of changes in 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 price volatility on our cash flows. By removing a significant portion of this price volatility on our future production through December 2016, we have mitigated, but not eliminated, the potential effects of changing 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 our 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.

Cardinal and UEO generate revenues from fees charged for gathering, compressing, processing, fractionating and storing natural gas and natural gas liquids. The primary drivers of revenues are the capacity of our midstream facilities and the production available for gathering, processing and fractionating. As we account for our investments in Cardinal and UEO using the equity method of accounting, our proportionate share of their revenues or expenses is reflected in “Income from unconsolidated affiliates” in our consolidated statements of operations.

Utica Shale

Primarily through acquisitions completed in 2009 and 2010, we hold over 170,000 net working interest acres in Pennsylvania and Ohio and an approximate 2% average ORRI in 880,000 gross acres in Ohio which we believe may be prospective for the Utica Shale. In addition, partnerships managed by EnerVest own acreage which may be prospective for the Utica Shale. At December 31, 2013, our estimated net proved reserves in the Utica Shale were not material to us. Exploration and development activities targeting the Utica Shale are in the early stages, and it is possible that our estimates of the acreage in Ohio that we believe is prospective for the Utica Shale may change, perhaps materially, as additional exploration and development activities are conducted in the area. We do not expect to fully develop our Utica Shale properties for our account.

In mid–2012, we initiated the process for the monetization of a majority of our working interest acres related to the Utica Shale, and in 2013, we, along with certain institutional partnerships managed by EnerVest, signed agreements to divest a portion of our Utica Shale acreage in Ohio. Through December 2013, we have closed on sales with proceeds of $44.1 million for these acres, and we expect additional closings on these acres in 2014. Additional monetizations could take many forms, and we cannot at this time predict the type of transactions we may enter into or the type or amount of consideration we may receive. We may not be successful in our additional efforts to monetize the Utica Shale properties, it may take longer to complete the divestiture process than we expect, or we may decide to delay the monetization of all or a portion of the Utica Shale properties.

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 proved 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, natural gas and natural gas liquids 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 reserves that will be produced from a field, the timing of this future production, future costs to produce the oil, natural gas and natural gas liquids 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, Natural Gas and Natural Gas Liquids Reserves

Our estimates of proved reserves are based on the quantities of oil, natural gas and natural gas liquids 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, natural gas and natural gas liquids production. We generally hedge a substantial, but varying, portion of our anticipated production for the next 12 – 36 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 reasonably assured. 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,		
	2013	**2012**	**2011**
Production data:			
Oil (MBbls)	1,027	1,110	891
Natural gas liquids (MBbls)	2,146	1,742	1,096
Natural gas (MMcf)	42,651	42,536	29,247
Net production (MMcfe)	61,690	59,647	41,169
Average sales price per unit:			
Oil (Bbl)	$ 95.62	$ 91.94	$ 91.72
Natural gas liquids (Bbl)	30.86	36.02	52.99
Natural gas (Mcf)	3.43	2.75	3.99
Mcfe	5.04	4.72	6.23
Average unit cost per Mcfe:			
Production costs:			
Lease operating expenses	$ 1.69	$ 1.74	$ 1.81
Production taxes	0.19	0.18	0.27
Total	1.88	1.92	2.08
Asset retirement obligations accretion expense	0.08	0.09	0.10
Depreciation, depletion and amortization	1.85	1.90	1.82
General and administrative expenses	0.66	0.72	0.85

Year Ended December 31, 2013 Compared with the Year Ended December 31, 2012

Net loss for 2013 was $76.2 million compared with a net loss of $16.3 million for 2012. This change reflects (i) $84.0 million change in (loss) gain on derivatives, net and (ii) $50.9 million in increased impairment charges, offset by (iii) $41.3 million in increased gain on sales of oil and natural gas properties, (iv) $29.8 million of higher revenues, and (v) $4.1 million in decreased operating expenses

Oil, natural gas and natural gas liquids revenues for 2013 totaled $310.9 million, an increase of $29.2 million compared with 2012. This was the result of increases of $33.2 million related to higher prices for oil and natural gas and $12.9 million related to increased natural gas and natural gas liquids production offset by decreases of $9.0 million related to lower prices for natural gas liquids and $7.9 million related to decreased oil production.

Lease operating expenses for 2013 increased $0.9 million compared with 2012 as the result of $3.5 million from higher natural gas and natural gas liquids production offset by $1.7 million ($0.03 per Mcfe) of costs in 2012 associated with the sales of oil in tanks acquired in certain of our 2011 acquisitions and $0.9 million from a lower rate per Mcfe. Lease operating expenses per Mcfe were $1.69 in 2013 compared with $1.74 in 2012.

Dry hole and exploration costs for 2013 decreased $4.4 million compared with 2012 primarily as a result of decreased seismic costs at certain of our oil and natural gas properties in the Appalachian Basin.

Production taxes, which are generally based on a percentage of our oil, natural gas and natural gas liquids revenues, for 2013 increased $0.6 million compared with 2012 primarily due to increased oil, natural gas and natural gas liquids revenues. Production taxes for 2013 were $0.19 per Mcfe compared with $0.18 per Mcfe for 2012.

Depreciation, depletion and amortization ("DD&A") for 2013 increased $0.4 million compared with 2012 due to $3.7 million from increased production offset by $3.3 million from a lower DD&A rate. The lower DD&A rate per Mcfe reflects the impact that changes in prices had on our reserves estimates. DD&A for 2013 was $1.85 per Mcfe compared with $1.90 per Mcfe for 2012.

General and administrative expenses for 2013 totaled $40.7 million, a decrease of $2.0 million compared with 2012. This decrease is primarily the result of $3.1 million of lower fees paid to EnerVest under the omnibus agreement and $0.7 million of decreased due diligence costs, partially offset by $1.0 million of higher equity compensation costs. General and administrative expenses were $0.66 per Mcfe in 2013 compared with $0.72 per Mcfe in 2012.

In 2013, we incurred impairment charges of $85.3 million. Of this amount, $76.3 million related to oil and natural gas properties that were written down to their fair value as determined based on the expected present value of the future net cash flows from proved reserves. Significant assumptions associated with the calculation of discounted cash flows used in the impairment analysis included estimates of future oil and natural gas prices, production costs, development expenditures, anticipated production of proved reserves, appropriate risk–adjusted discount rates and other relevant data. The remainder of the impairment charges consisted of $8.5 million of leasehold impairment charges and $0.5 million of an impairment charge to write down assets held for sale to their fair value. In 2012, we incurred impairment charges of $34.5 million. Of this amount, $31.9 million related to oil and natural gas properties that were written down to their fair value, $2.1 million related to leasehold impairment charges and $0.5 million related to additional impairment charges to write down assets held for sale to their fair value.

In 2013, we recognized a gain of $41.3 million on the sale of oil and natural gas properties in the Utica Shale area of Ohio.

(Loss) gain on derivatives, net was $(17.3) million for 2013 compared with $66.7 million for 2012. This change was attributable to increases in future natural gas prices. The 12 month forward prices at December 31, 2013 for natural gas averaged $4.19 per Bbl compared with $3.54 per Bbl at December 31, 2012.

Interest expense for 2013 increased $0.4 million compared with 2012 due to an increase of $10.9 million from a higher weighted average long–term debt balance offset by $4.1 million from a lower weighted average effective interest rate and $6.4 million of higher capitalized interest related to our investments in unconsolidated affiliates.

Year Ended December 31, 2012 Compared with the Year Ended December 31, 2011

Net loss for 2012 was $16.3 million compared with net income of $102.6 million for 2011. This change reflects (i) $23.6 million in increased revenues and (ii) $5.4 million in decreased dry hole and exploration costs, offset by (iii) $27.2 million in decreased (loss) gain on derivatives, net, (iv) $74.9 million in increased operating expenses, (v) $23.4 million in increased impairment charges, (vi) $18.1 million in higher interest expense and (vii) $4.0 million of decreased gain on sale of oil and natural gas properties.

Oil, natural gas and natural gas liquids revenues for 2012 totaled $281.7 million, an increase of $25.4 million compared with 2011. This increase was the result of $79.9 million related to increased production and $0.2 million from higher prices for oil partially offset by $54.7 million related to lower prices for natural gas and natural gas liquids.

Lease operating expenses for 2012 increased $29.2 million compared with 2011 as the result of $31.6 million related to increased production from our 2011 acquisitions and our expanded development drilling program and $1.7 million ($0.03 per Mcfe) associated with the sales of oil in tanks acquired in certain of our 2011 acquisitions offset by $4.1 million due to a lower unit cost per Mcfe for our acquisitions of oil and natural gas properties in the Barnett Shale. Lease operating expenses per Mcfe were $1.74 in 2012 compared with $1.81 in 2011.

Dry hole and exploration costs for 2012 decreased $5.4 million compared with 2011. Lower dry hole costs of $8.1 million were partially offset by increased seismic costs at certain of our oil and natural gas properties in the Appalachian Basin and the Barnett Shale.

Production taxes, which are generally based on a percentage of our oil, natural gas and natural gas liquids revenues, decreased $0.3 million compared with 2011 as the result of $3.7 million from lower average realized prices offset by $3.4 million from increased production. Production taxes for 2012 were $0.18 per Mcfe compared with $0.27 per Mcfe for 2011.

Asset retirement obligations accretion expense for 2012 increased $1.2 million compared with 2011 due to the oil and natural gas properties that we acquired in 2011. Asset retirement obligations accretion expense for 2012 was $0.09 per Mcfe compared with $0.10 per Mcfe for 2011.

DD&A for 2012 increased $38.7 million compared with 2011 due to $35.0 million from higher production and $3.4 million from a higher average DD&A rate per unit. The higher average DD&A rate per unit reflects the change that decreased prices for natural gas and natural gas liquids had on our reserves estimates. Depreciation, depletion and amortization for 2012 was $1.90 per Mcfe compared with $1.82 per Mcfe for 2011.

General and administrative expenses for 2012 totaled $42.7 million, an increase of $7.7 million compared with 2011. This increase is the result of (i) $6.6 million of higher equity compensation costs, (ii) $2.2 million of higher fees paid to EnerVest under the omnibus agreement due to an increase in operations from our acquisitions of oil and natural gas properties in 2011 and (iii) $0.6 million of increased payroll costs, partially offset by a decrease of $1.9 million of due diligence costs related to our acquisitions of oil and natural gas properties in December 2011. General and administrative expenses were $0.72 per Mcfe in 2012 compared with $0.85 per Mcfe in 2011.

In 2012, we incurred impairment charges of $34.5 million. Of this amount, due to lower natural gas prices and their effect on our reserves, we recorded $31.9 million of impairment charges related to oil and natural gas properties that were written down to their fair value as determined based on the expected present value of the future net cash flows from proved reserves. Significant assumptions associated with the calculation of discounted cash flows used in the impairment analysis included estimates of future oil and natural gas prices, production costs, development expenditures, anticipated production of proved reserves, appropriate risk–adjusted discount rates and other relevant data. The remainder of the impairment charges consisted of $2.1 million of leasehold impairment charges and $0.5 million of additional impairment charges to write down assets held for sale to their fair value. In 2011, we incurred impairment charges of $11.0 million to write down oil and natural gas properties to their fair value. Of this amount, $10.4 million related to oil and natural gas properties that were written down to their fair values prior to being sold and $0.6 million related to leasehold impairments of unproved oil and natural gas properties.

(Loss) gain on derivatives, net was $66.7 million for 2012 compared with $93.9 million for 2011. This change was attributable to decreases in future oil prices offset by increases in natural gas prices. The 12 month forward prices at December 31, 2012 for oil averaged $93.22 per Bbl compared with $98.77 per Bbl at December 31, 2011, and the 12 month forward prices for natural gas at December 31, 2012 averaged $3.54 per MMBtu compared with $3.25 per MMBtu at December 31, 2011.

Interest expense for 2012 increased $18.1 million compared with 2011 due to increases of $15.2 million from a higher weighted average long–term debt balance and $3.8 million from a higher weighted average effective interest rate offset by $0.9 million of capitalized interest related to our investments in unconsolidated affiliates.

LIQUIDITY AND CAPITAL RESOURCES

Historically, our primary sources of liquidity and capital have been issuances of equity and debt securities, borrowings under our credit facility and cash flows from operations. 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, contributions to our midstream investments, distributions to our unitholders and general partner and working capital needs. For 2014, we believe that cash on hand, proceeds from sales of assets, net cash flows generated from operations and borrowings under our credit facility will be adequate to fund our capital budget, pay distributions to our unitholders and general partner and satisfy our short–term liquidity needs. We may also utilize borrowings under our credit facility and 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.

Long–term Debt

As of December 31, 2013, we have a $1.0 billion credit facility that expires in April 2016. 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, 2013, the borrowing base was $730.0 million, and we had $481.0 million outstanding.

As of December 31, 2013, we have $500.0 million in aggregate principal amount outstanding of 8.0% senior notes due 2019. As of December 31, 2013, the aggregate carrying amount of the senior notes due 2019 was $499.3 million.

For additional information about our long–term debt, such as interest rates and covenants, please see “Item 8. Financial Statements and Supplementary Data” contained herein.

Cash and Cash Equivalents

At December 31, 2013, we had $11.7 million of cash and cash equivalents, which included $4.9 million of short–term investments. With regard to our short–term investments, we invest in money market accounts with major financial institutions.

Counterparty Exposure

All of our 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 contracts and we could incur a loss. As of December 31, 2013, all of our counterparties have performed pursuant to their derivative contracts.

Cash Flows

	2013	2012	2011
Operating activities	$ 152,499	$ 209,515	$ 167,212
Investing activities	(337,970)	(273,508)	(518,962)
Financing activities	189,683	41,167	358,935

Operating Activities

Cash flows from operating activities provided $152.5 million and $209.5 million in 2013 and 2012, respectively. The significant factor in the decrease was $84.2 million of decreased cash settlements from our matured derivative contracts offset by a $29.2 million increase in our oil, natural gas and natural gas liquids revenues. Cash flows from operating activities were $209.5 million and $167.2 million in 2012 and 2011, respectively. The increase was primarily due to $23.6 million of higher revenues and $59.9 million of increased cash settlements from our matured derivative contracts, partially offset by $31.2 million of higher cash operating expenses and $20.3 million of increased cash paid for interest.

Investing Activities

During 2013, we spent $66.0 million for an acquisition of oil and natural gas properties, and we received $8.0 million in final purchase price settlements related to our August 2012 acquisition of additional working interests in acreage in Ohio. We spent $98.0 million for additions to our oil and natural gas properties and increased our investment in our midstream assets by $221.1 million. In addition, we received $44.1 million from the sale of oil and natural gas properties and incurred $5.0 million of prepaid drilling costs.

During 2012, we spent $120.0 million for acquisitions of oil and natural gas properties and $129.8 million for additions to our oil and natural gas properties. We also increased our investment in our midstream assets by $33.8 million. In addition, we received $5.5 million from the sale of oil and natural gas properties and $4.6 million from the settlements of acquired derivatives.

During 2011, we spent $463.6 million for the acquisition of oil and natural gas properties and $75.9 million for additions to our oil and natural gas properties. In addition, we received $6.6 million from settlements of derivatives acquired in our December 2010 acquisition of oil and natural gas properties and $14.0 million in proceeds from the sales of oil and natural gas properties.

Financing Activities

During 2013, we received proceeds of $204.3 million, after payment of offering costs of $0.2 million, from our public equity offering in October 2013, and we received contributions of $4.5 million from our general partner in order to maintain its 2% interest in us. We used the proceeds to repay $208.0 million of indebtedness outstanding under our credit facility. We also received $329.0 million from borrowings under our credit facility and paid distributions of $140.1 million to holders of our common units and phantom units and our general partner.

During 2012, we received proceeds of $262.5 million, after payment of offering costs of $0.3 million, from our public equity offering in February 2012 and $201.9 million, after deducting $4.1 million for underwriters' discounts and payment of offering expenses, from our debt offering in March 2012. We used the proceeds to repay $460.0 million of indebtedness outstanding under our credit facility. We also received $160.0 million from borrowings under our credit facility and contributions of $5.7 million from our general partner in order to maintain its 2% interest in us. In addition, we paid distributions of $128.9 million to holders of our common units, Class B units and our general partner.

During 2011, we received proceeds of $146.8 million, after payment of offering costs of $0.3 million, from our public equity offering in March 2011, and we received contributions of $3.2 million from our general partner in order to maintain its 2% interest in us. We also received net proceeds of $291.5 million from our debt offering in March 2011, after deducting offering expenses of $1.0 million. We used the proceeds from these offerings and cash flows from operations to repay $436.5 million of borrowings outstanding under our credit facility. In addition, we borrowed $477.5 million under our credit facility to finance our acquisitions, paid distributions of $115.1 million to holders of our common units and our general partner and paid $6.7 million in loan costs related to our $1.0 billion credit facility.

Capital Requirements

In 2014, we currently expect spending for additions to our oil and natural gas properties to be between $95.0 million and $115.0 million and our commitment to fund the construction activities for our unconsolidated affiliates to be between $115.0 million and $135.0 million. We also currently expect to make distributions of approximately $38.7 million per quarter to holders of our common units, phantom units and general partner based on our current quarterly distribution rate of $0.771 per unit outstanding and our common units and phantom units outstanding as of February 14, 2014. We expect to fund these amounts with cash on hand, proceeds from sales of assets, net cash flows generated from operations and borrowings under our credit facility.

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 2014 through the issuance of equity or debt securities.

Contractual Obligations

	Payments Due by Period (amounts in thousands)				
	Total	Less Than 1 Year	1 – 3 Years	4 – 5 Years	After 5 Years
Total debt	$ 981,000	$ –	$ 481,000	$ –	$ 500,000
Estimated interest payments (1)	240,173	52,217	96,289	80,000	11,667
Transportation commitments (2)	5,360	618	1,237	1,237	2,268
Purchase obligation (3)	12,100	12,100	–	–	–
Total	$ 1,238,633	$ 64,935	$ 578,526	$ 81,237	$ 513,935

(1) Amounts represent the expected cash payments for interest based on (i) the amount outstanding under our credit facility as of December 31, 2013 and the weighted average interest rate for 2013 of 2.54%, and (ii) our $500.0 million in aggregate principal amount of 8.0% senior notes due 2019. Such amounts do not include the effects of our interest rate swaps.

(2) Amounts represent commitments under a firm transportation agreement at current rates.

(3) Amounts represent payments to be made under our omnibus agreement with EnerVest based on the amount that we will pay in 2014. This amount will increase or decrease as we purchase or divest assets. While these payments will continue for periods subsequent to December 31, 2014, 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, 2013 is $103.2 million.

Off–Balance Sheet Arrangements

As of December 31, 2013, we had no off–balance sheet arrangements.

RECENT ACCOUNTING STANDARDS

Please see “Item 8. Financial Statements and supplementary Data” contained herein for additional information.

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 and plans, including plans for the sale of acreage in the Utica Shale;
- our estimated net proved reserves, PV–10 value and standardized measure;
- market prices;
- our anticipated future gathering, processing and fractionation activities;
- 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, natural gas and natural gas liquids;
- significant disruptions in the financial markets;
- future capital requirements and availability of financing;
- our limited control over operations in our midstream business;
- uncertainty inherent in estimating our reserves;
- risks associated with drilling and operating wells;
- discovery, acquisition, development and replacement of reserves;
- cash flows and liquidity;
- timing and amount of future production of oil, natural gas and natural gas liquids;
- availability of drilling and production equipment;
- marketing of oil, natural gas and natural gas liquids;
- developments in oil and natural gas producing countries;
- competition;
- general economic conditions;
- governmental regulations;
- activities taken or non–performance by third parties, including suppliers, contractors, operators, transporters and purchasers of our production and counterparties to our derivative financial instrument contracts;
- hedging decisions, including whether or not to enter into derivative financial instruments;
- 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, natural gas and natural gas liquids. Declines in prices may materially adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower prices also may reduce the amount of oil, natural gas or natural gas liquids that we can produce economically. A decline in prices could have a material adverse effect on the estimated value and estimated quantities of our reserves, our ability to fund our operations and our financial condition, cash flows, results of operations and access to capital. Historically, 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 derivatives to manage or reduce market risk, but do not enter into derivatives for speculative purposes.

We do not designate these or future derivatives as hedges for accounting purposes. Accordingly, the changes in the fair value of these derivatives 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, commodity contracts to reduce our risk of changes in the prices of oil, natural gas and natural gas liquids. 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, natural gas and natural gas liquids.

We have entered into commodity contracts to hedge significant amounts of our anticipated production through December 2016. As of December 31, 2013, we have commodity contracts covering approximately 55% of our production attributable to our estimated net proved reserves through December 2016, as estimated in our reserve report prepared by third party engineers using prices, costs and other assumptions required by SEC rules. Our actual production will vary from the amounts estimated in our reserve reports, perhaps materially. Please read the disclosures under “Our estimated 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 commodity contracts at December 31, 2013 was a net asset of $44.3 million. A 10% change in 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 commodity contracts of approximately $56.9 million. Please see “Item 8. Financial Statements and Supplementary Data” contained herein for additional information.

Interest Rate Risk

Our floating rate credit facility and interest rate swaps also expose 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. If interest rates on our facility increased by 1%, interest expense for 2013 would have increased by approximately $5.0 million. The fair value of our interest rate swaps at December 31, 2013 was a net liability of $5.0 million. A 1% change in interest rates 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 interest rate swaps) of our interest rate swaps of approximately $1.7 million. Please see “Item 8. Financial Statements and supplementary Data” contained herein for additional information.

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 (1992)* 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, 2013.

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, 2013 which is included in "Item 8. Financial Statements and Supplementary Data" contained herein.

/s/ MARK A. HOUSER	/s/ MICHAEL E. MERCER
Mark A. Houser	Michael E. Mercer
Chief Executive Officer of EV Management, LLC,	Chief Financial Officer of EV Management, LLC,
general partner of EV Energy, GP, L.P.,	general partner of EV Energy GP, L.P.,
general partner of EV Energy Partners, L.P.	general partner of EV Energy Partners, L.P.

Houston, TX
February 28, 2014

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, 2013 and 2012, 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, 2013. We also have audited the Partnership's internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control — Integrated Framework (1992)* 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 EV Energy Partners, L.P. and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 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, 2013, based on the criteria established in *Internal Control — Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/DELOITTE & TOUCHE LLP
Houston, Texas
February 28, 2014

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

	December 31, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 11,698	$ 7,486
Accounts receivable:		
Oil, natural gas and natural gas liquids revenues	37,661	34,909
Related party	2,873	1,422
Other	1,111	11,263
Derivative asset	13,543	40,771
Other current assets	6,916	1,750
Assets held for sale	8,012	–
Total current assets	81,814	97,601
Oil and natural gas properties, net of accumulated depreciation, depletion and amortization; December 31, 2013, $569,770; December 31, 2012, $389,206	1,829,062	1,875,890
Other property, net of accumulated depreciation and amortization; December 31, 2013, $754; December 31, 2012, $598	1,259	1,325
Long–term derivative asset	29,088	45,839
Investments in unconsolidated affiliates	254,978	34,545
Other assets	8,782	10,214
Total assets	$ 2,204,983	$ 2,065,414
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 46,876	$ 40,171
Derivative liability	3,348	–
Liabilities related to assets held for sale	2,155	–
Total current liabilities	52,379	40,171
Asset retirement obligations	99,133	102,707
Long–term debt	980,297	859,218
Other long–term liabilities	1,241	3,494
Commitments and contingencies		
Owners' equity:		
Common unitholders – 48,349,080 units and 42,320,707 units issued and outstanding as of December 31, 2013 and 2012, respectively	1,083,718	1,072,175
General partner interest	(11,785)	(12,351)
Total owners' equity	1,071,933	1,059,824
Total liabilities and owners' equity	$ 2,204,983	$ 2,065,414

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, 2013	2012	2011
Revenues:			
Oil, natural gas and natural gas liquids revenues	$ 310,883	$ 281,749	$ 256,370
Transportation and marketing–related revenues	4,429	3,731	5,470
Total revenues	315,312	285,480	261,840
Operating costs and expenses:			
Lease operating expenses	104,465	103,605	74,419
Cost of purchased natural gas	3,242	2,600	4,078
Dry hole and exploration costs	2,380	6,771	12,140
Production taxes	11,476	10,911	11,247
Asset retirement obligations accretion expense	4,925	5,116	3,914
Depreciation, depletion and amortization	113,818	113,381	74,723
General and administrative expenses	40,677	42,682	34,968
Impairment of oil and natural gas properties	85,341	34,453	11,037
Gain on sales of oil and natural gas properties	(41,309)	–	(4,017)
Total operating costs and expenses	325,015	319,519	222,509
Operating (loss) income	(9,703)	(34,039)	39,331
Other (expense) income, net:			
(Loss) gain on derivatives, net	(17,262)	66,734	93,907
Interest expense	(49,062)	(48,689)	(30,568)
Other income, net	277	705	325
Total other (expense) income, net	(66,047)	18,750	63,664
(Loss) income before income taxes and equity in (loss) income of unconsolidated affiliates	(75,750)	(15,289)	102,995
Income taxes	(133)	(1,078)	(354)
(Loss) income before equity in (loss) income of unconsolidated affiliates	(75,883)	(16,367)	102,641
Equity in (loss) income of unconsolidated affiliates	(344)	18	–
Net (loss) income	$ (76,227)	$ (16,349)	$ 102,641
Net (loss) income per limited partner unit:			
Basic	$ (1.76)	$ (0.38)	$ 2.71
Diluted	$ (1.76)	$ (0.38)	$ 2.68
Weighted average limited partner units outstanding:			
Basic	43,691	41,952	33,895
Diluted	43,691	41,952	34,183

See accompanying notes to consolidated financial statements.

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

	Year Ended December 31,		
	2013	**2012**	**2011**
Cash flows from operating activities:			
Net (loss) income	$ (76,227)	$ (16,349)	$ 102,641
Adjustments to reconcile net (loss) income to net cash flows provided by operating activities:			
Dry hole costs	616	1,100	9,220
Asset retirement obligations accretion expense	4,925	5,116	3,914
Depreciation, depletion and amortization	113,818	113,381	74,723
Equity–based compensation	17,470	16,433	9,834
Impairment of oil and natural gas properties	85,341	34,453	11,037
Gain on sales of oil and natural gas properties	(41,309)	–	(4,017)
Loss (gain) on derivatives, net	17,262	(66,734)	(93,907)
Cash settlements of matured derivative contracts	30,066	114,343	52,416
Amortization of deferred loan costs	2,333	2,183	1,348
Equity in loss (income) of unconsolidated affiliates	344	(18)	–
Distributions from unconsolidated affiliates	285	79	–
Other	(296)	2,165	563
Changes in operating assets and liabilities:			
Accounts receivable	(2,671)	(1,773)	(6,505)
Other current assets	(68)	51	(342)
Accounts payable and accrued liabilities	1,316	5,185	7,362
Other, net	(706)	(100)	(1,075)
Net cash flows provided by operating activities	152,499	209,515	167,212
Cash flows from investing activities:			
Acquisitions of oil and natural gas properties	(57,976)	(120,033)	(463,624)
Additions to oil and natural gas properties	(97,946)	(129,783)	(75,913)
Prepaid drilling costs	(5,041)	–	–
Investments in unconsolidated affiliates	(221,101)	(33,811)	–
Proceeds from sales of oil and natural gas properties	44,056	5,522	14,012
Distributions from unconsolidated affiliates	38	19	–
Settlements from acquired derivatives	–	4,578	6,563
Net cash flows used in investing activities	(337,970)	(273,508)	(518,962)
Cash flows from financing activities:			
Long–term debt borrowings	329,000	160,000	477,500
Repayments of long–term debt borrowings	(208,000)	(460,000)	(436,500)
Proceeds from debt offering	–	206,000	292,500
Loan costs paid	–	(4,152)	(7,698)
Proceeds from public equity offerings	204,527	262,833	147,108
Offering costs	(226)	(304)	(347)
Contributions from general partner	4,508	5,714	3,191
Distributions paid	(140,126)	(128,924)	(115,101)
Distribution related to acquisition	–	–	(1,718)
Net cash flows provided by financing activities	189,683	41,167	358,935
Increase (decrease) in cash and cash equivalents	4,212	(22,826)	7,185
Cash and cash equivalents – beginning of year	7,486	30,312	23,127
Cash and cash equivalents – end of year	$ 11,698	$ 7,486	$ 30,312

See accompanying notes to consolidated financial statements.

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

	Common Unitholders	Class B Unitholders	General Partner Interest	Total Owners' Equity
Balance, December 31, 2010	$ 779,327	$ –	$ (5,380)	$ 773,947
Conversion of 80,534 vested phantom units	3,508	–	–	3,508
Issuance of 3,873,357 Class B units	–	–	–	–
Proceeds from public equity offerings, net of offering costs of $347	146,761	–	–	146,761
Contributions from general partner	–	–	3,191	3,191
Distributions	(101,337)	–	(13,764)	(115,101)
Distribution related to acquisition	–	–	(1,718)	(1,718)
Equity–based compensation	6,810	–	–	6,810
Net income	100,356	232	2,053	102,641
Balance, December 31, 2011	935,425	232	(15,618)	920,039
Conversion of 41,075 vested phantom units	2,836	–	–	2,836
Proceeds from public equity offering, net of offering costs of $304	262,529	–	–	262,529
Contributions from general partner	–	–	5,714	5,714
Distributions	(114,501)	(11,845)	(2,578)	(128,924)
Equity–based compensation	12,278	1,243	458	13,979
Conversion of Class B units	(11,530)	11,530	–	–
Net loss	(14,862)	(1,160)	(327)	(16,349)
Balance, December 31, 2012	1,072,175	–	(12,351)	1,059,824
Conversion of 40,264 vested phantom units	2,365	–	–	2,365
Proceeds from public equity offering, net of offering costs of $226	204,301	–	–	204,301
Contributions from general partner	–	–	4,508	4,508
Distributions	(137,363)	–	(2,763)	(140,126)
Equity–based compensation	16,942	–	346	17,288
Net loss	(74,702)		(1,525)	(76,227)
Balance, December 31, 2013	$ 1,083,718	$ –	$ (11,785)	$ 1,071,933

See accompanying notes to consolidated financial statements.

EV Energy Partners, L.P.
Notes to Consolidated Financial Statements

NOTE 1. ORGANIZATION AND NATURE OF BUSINESS

EV Energy Partners, L.P. (the "Parent") and its wholly owned subsidiaries (collectively, the "Partnership") are a publicly held limited partnership. 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.

The Partnership has two reportable segments: exploration and production and midstream. The exploration and production segment is responsible for the acquisition, development and production of the Partnership's oil and natural gas properties. The midstream segment, which consists of the Partnership's investments in Cardinal Gas Services, LLC ("Cardinal") and Utica East Ohio Midstream LLC ("UEO"), is engaged in the construction and operation of natural gas processing, natural gas liquids fractionation, connecting pipeline infrastructure and gathering systems to serve production in the Utica Shale area in Ohio.

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. 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, 2013 and 2012, 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, natural gas and natural gas liquids 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 $133.8 million and $133.5 million as of December 31, 2013 and December 31, 2012, 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. For 2013, 2012 and 2011, we recorded dry hole and exploration costs of $2.4 million, $6.8 million and $12.1 million, respectively.

No gains or losses are recognized upon the disposition of proved 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 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 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 2013, 2012 and 2011, we recorded impairment charges of $76.9 million, $32.4 million and $10.4 million, respectively, related to proved oil and natural gas properties as the carrying amounts of such properties were determined not to be recoverable (see Note 8).

Unproved oil and natural gas properties are assessed periodically on a property–by–property basis, and any impairment in value is recognized. For 2013, 2012 and 2011, we recorded leasehold impairment charges of $8.5 million, $2.1 million and $0.6 million, respectively, related to unproved oil and natural gas properties.

Investments in Unconsolidated Affiliates

We account for our investments in unconsolidated affiliates using the equity method of accounting. Accordingly, we recognize our proportionate share of their earnings or losses in the period in which they are reported in their financial statements rather than in the period in which they declare a dividend. Dividends received from these unconsolidated affiliates decrease the carrying amount of our investments.

Asset Retirement Obligations

An asset retirement obligation ("ARO") represents the future abandonment costs of tangible assets, such as wells, service assets, 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 assured. 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, 2013 or 2012.

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, natural gas and natural gas liquids.

We have elected not to designate our derivatives as hedging instruments. Changes in the fair value of derivatives are recorded immediately to earnings as "(Loss) gain on derivatives, net" in our consolidated statements of operations.

Concentration of Credit Risk

All of our 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 contracts and we could incur a loss. As of December 31, 2013, all of our counterparties have performed pursuant to their derivative contracts.

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 2013, 2012 and 2011, no customer accounted for greater than 10% 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 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2011–11, *Disclosures about Offsetting Assets and Liabilities.* This ASU affects all entities that have financial instruments and derivative instruments that are either offset or subject to an enforceable master netting arrangement or similar agreement. ASU 2011–11 requires an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. In January 2013, the FASB issued ASU 2013–01, *Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities,* to clarify the scope of ASU 2011–11. The provisions of both ASU 2011–11 and ASU 2013–01 are applicable to annual reporting periods beginning on or after January 1, 2013 and interim periods within those annual periods. We adopted ASU 2011–11 and 2013–01 on January 1, 2013, and the adoption did not impact our operating results, financial position or cash flows, but did impact our disclosures on offsetting arrangements (see Note 7).

No other new accounting pronouncements issued or effective during the year ended December 31, 2013 have had or are expected to have a material impact on our consolidated financial statements.

Subsequent Event

In January 2014, we closed on the sale of our assets held for sale and received proceeds of $5.8 million.

We evaluated subsequent events for appropriate accounting and disclosure through the date these 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, 2013, the aggregate amount of our common units that may be awarded under the plan was 4.5 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.

Phantom Units

Equity Awards

We account for 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:

	2013	2012	2011
Weighted average fair value of phantom units	$ 31.92	$ 58.92	$ 63.87
Expected volatility	30.780%	37.870%	36.803%
Risk–free interest rate	0.68%	0.40%	0.40%
Dividend yield	0.0%	0.0%	0.0%
Expected life (years)	4.0	4.0	4.0

We calculated estimated volatility using historical daily prices for two years prior to the grant date. The risk–free interest rate was based on U.S. Treasury yield curves. The dividend yield is not taken into account as recipients are entitled to receive all distributions underlying the 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, 2012	840,649	$ 50.24
Granted	306,300	31.92
Vested	(199,175)	42.89
Forfeited	(25,018)	54.27
Nonvested phantom units as of December 31, 2013	922,756	$ 45.63

The total grant date fair value of the phantom units vested in 2013, 2012 and 2011 was $8.5 million, $4.8 million and $2.1 million, respectively.

We recognized compensation cost related to these phantom units of $11.9 million, $8.4 million and $4.9 million in 2013, 2012 and 2011. These costs are included in “General and administrative expenses” in our consolidated statements of operations.

As of December 31, 2013, there was $30.2 million of total unrecognized compensation cost related to unvested phantom units which is expected to be recognized over a weighted average period of 2.9 years.

Liability Awards

We accounted for phantom units issued prior to 2009 as liability awards, and the fair value of these phantom units was 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 was recognized for these phantom units based on the proportionate amount of the requisite service period that has been rendered to date and was net of estimated forfeitures. These phantom units were subject to graded vesting over a four year period.

Activity related to these phantom units is as follows:

Nonvested phantom units as of December 31, 2012	40,263
Vested	(40,263)
Nonvested phantom units as of December 31, 2013	–

The total fair value of the phantom units vested in 2013, 2012 and 2011 was $2.4 million, $2.8 million and $3.5 million, respectively.

We recognized compensation cost related to these phantom units of $0.2 million, $2.5 million and $3.0 million in 2013, 2012 and 2011, respectively. These costs are included in "General and administrative expenses" in our consolidated statements of operations.

Performance Units

In September 2011, we issued 0.3 million performance units to certain employees and executive officers of EV Management and its affiliates. These performance units vest 25% each year beginning in January 2012 subject to our common units achieving certain market prices. We accounted for the performance units as equity awards. We estimated the fair value of 0.1 million of the performance units using the Black–Scholes option pricing model, as the market price had already been achieved for those performance units. We estimated the fair value of the remainder of the market condition performance units using the Monte Carlo simulation model.

The following assumptions were used to estimate the weighted average fair value of the performance units:

	2011
Weighted average fair value of performance units	$ 64.07
Expected volatility	47.987%
Risk–free interest rate	0.56%
Expected quarterly distribution amount	$ 0.762
Expected life (years)	2.69

We calculated estimated volatility using historical daily prices prior to the grant date. The risk–free interest rate was based on U.S. Treasury yield curves. The dividend yield is not taken into account as recipients are entitled to receive all distributions underlying the performance units.

Activity related to these performance units is as follows:

	Number of Performance Units	Weighted Average Grant Date Fair Value per Performance Unit
Nonvested performance units as of December 31, 2012	318,500	$ 52.45
Vested	(83,500)	19.73
Forfeited	(10,000)	64.07
Nonvested performance units as of December 31, 2013	225,000	$ 64.07

The total grant date fair value of the performance units vested in 2013, 2012 and 2011 was $1.6 million, $1.7 million and $0.2 million, respectively.

We recognized compensation cost related to our performance units of $5.4 million, $5.6 million and $2.0 million in 2013, 2012 and 2011, respectively. These costs are included in "General and administrative expenses" in our consolidated statements of operations.

As of December 31, 2013, there was $5.6 million of total unrecognized compensation cost related to unvested performance units which is expected to be recognized over a weighted average period of 1.0 year.

NOTE 4. ACQUISITIONS

2013

In March 2013, we received final purchase price settlements of $8.0 million related to our August 2012 acquisition of additional working interests in acreage in Ohio.

In November 2013, we, along with certain institutional partnerships managed by EnerVest, acquired natural gas properties in the Barnett Shale. We acquired a 31% proportional interest in these properties for an aggregate purchase price of $66.0 million, subject to customary purchase price adjustments. We recognized $1.4 million of oil, natural gas and natural gas liquids revenues related to these acquisitions in our consolidated statement of operations for 2013.

We accounted for these acquisitions as business combinations. Pro forma results of operations have not been presented as the amounts would not be material to our consolidated statements of operations.

The recognized fair values of the identifiable assets acquired and liabilities assumed in connection with the November 2013 acquisitions are as follows:

Accounts receivable – related party	$	(650)
Other current assets		57
Proved oil and natural gas properties		60,607
Unproved oil and natural gas properties		6,018
Other assets		900
Accounts payable and accrued liabilities		18
Asset retirement obligations		(976)
	$	65,974

The amounts included in the table above represent preliminary estimates of the fair values of the identifiable assets acquired and liabilities assumed for these acquisitions. We expect to finalize the fair values in 2014.

2012

In February 2012 and March 2012, we, along with certain institutional partnerships managed by EnerVest, had additional closings on the oil and natural gas properties in the Barnett Shale that we acquired in December 2011. We acquired a 31.63% proportional interest in these properties for an aggregate purchase price of $36.5 million, subject to customary purchase price adjustments.

In April 2012, we received final purchase price settlements of $1.7 million related to our acquisitions of oil and natural gas properties in the Barnett Shale in December 2011.

In May 2012, we paid a final purchase price settlement of $0.9 million related to our acquisition of oil and natural gas properties in the Mid–Continent area in November 2011.

In August 2012, we acquired additional working interests in acreage in Ohio that we believe may be prospective for the Utica Shale for $75.2 million, after preliminary purchase price adjustments.

In November 2012, we acquired oil and natural gas assets for $1.1 million, subject to customary purchase price adjustments.

We accounted for these acquisitions as business combinations. Pro forma results of operations have not been presented as the amounts would not be material to our consolidated statements of operations.

2011

On November 1, 2011, we acquired oil and natural gas properties in the Mid–Continent area for $74.3 million, subject to customary purchase price adjustments. We recognized $1.8 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, 2011.

On December 1, 2011, we, along with certain institutional partnerships managed by EnerVest, acquired oil and natural gas properties in the Barnett Shale. We acquired a 31.02% proportional interest in these properties for $75.7 million, subject to customary purchase price adjustments. We recognized $1.7 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, 2011.

On December 20, 2011, we, along with certain institutional partnerships managed by EnerVest, acquired additional oil and natural gas properties in the Barnett Shale. We acquired a 31.63% proportional interest in these properties for $271.4 million, subject to customary purchase price adjustments. We recognized $2.2 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, 2011.

We accounted for these acquisitions as business combinations. The following table reflects pro forma revenues, net income and net income per limited partner unit for the year ended December 31, 2011 as if these acquisitions had taken place on January 1, 2010. These unaudited pro forma amounts do not purport to be indicative of the results that would have actually been obtained during the period presented or that may be obtained in the future.

	2011
Revenues	$ 350,229
Net income	140,409
Net income per limited partner unit:	
Basic	$ 3.80
Diluted	$ 3.77

In addition to the acquisitions described above, we also made the following smaller acquisitions and accounted for them as business combinations:

- we received final purchase price settlements totaling $4.1 million related to our September 2010 and December 2010 acquisitions of oil and natural gas properties in the Mid–Continent area and the Barnett Shale;
- we, along with certain institutional partnerships managed by EnerVest, acquired a proportional 31.02% interest in oil and natural gas properties in Barnett Shale for an aggregate purchase price of $17.3 million; and
- we acquired oil and natural gas properties in the Appalachian Basin from certain institutional partnerships managed by EnerVest for $31.1 million, subject to customary purchase price adjustments.

As we acquired the oil and natural gas properties in the Appalachian Basin from certain institutional partnerships managed by EnerVest, we carried over the historical costs related to EnerVest's interests and applied purchase accounting to the remaining interests acquired. As a result, we recorded a deemed distribution of $1.7 million that represents the difference between the recognized fair values of the identifiable assets acquired and liabilities assumed and the amount paid for the acquisition.

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

Accounts receivable	$ 2,698
Other current assets	1,584
Proved oil and natural gas properties	428,478
Unproved oil and natural gas properties	43,947
Other property	12
Other assets	7,706
Accounts payable and accrued liabilities	(523)
Asset retirement obligations	(19,855)
	$ 464,047

NOTE 5. DIVESTITURES

In 2013, we, along with certain institutional partnerships managed by EnerVest, signed agreements to divest a portion of our Utica Shale acreage in Ohio. Through December 2013, we had closed on sales with proceeds of $44.1 million for these acres, and we expect additional closings on these acres in 2014.

In 2012, the assets and liabilities that were held for sale as of December 31, 2011 were sold for $5.5 million. We also sold non–core oil and natural gas wells for $0.5 million, which is recorded within accounts receivable as of December 31, 2012.

In December 2011, we entered into a Purchase and Sale Agreement and a Development Agreement with Total E&P USA, Inc. ("Total"), a subsidiary of Total S.A., and Chesapeake Energy Corporation, whereby Total acquired an undivided 25% interest in certain acres in the Utica Shale and agreed to fund certain future development costs. We received $4.2 million in cash for our acres. We continue to own working interests in these acres. As of December 31, 2013, our portion of future development cost to be carried by Total was $9.4 million.

In 2011, we sold oil and natural gas properties in the Mid–Continent and Central and East Texas areas for $9.8 million.

NOTE 6. INVESTMENTS IN UNCONSOLIDATED AFFILIATES

The most significant of our investments in unconsolidated affiliates are Cardinal and UEO. We own 9% of Cardinal and, through December 2012, we owned 8% of UEO. Cardinal and UEO are engaged in the construction and operation of natural gas processing, natural gas liquids fractionation, connecting pipeline infrastructure and gathering systems to serve production in the Utica Shale area in Ohio.

In October 2012, we signed an agreement whereby we and EnerVest will dedicate production from certain of our operated acres in Ohio to the UEO facilities in exchange for the right to increase our ownership in UEO from 8% to 21%. The increase in our ownership in UEO was subject to certain conditions being met on or before March 2013. On December 20, 2012, such conditions were satisfied, and in January 2013, we paid $33.3 million to increase our ownership in UEO from 8% to 21%.

Summarized combined financial information for Cardinal and UEO is as follows as of and for the years ended December 31:

	2013	2012
Current assets	$ 71,153	$ 82,609
Noncurrent assets	1,528,518	389,799
Total assets	$ 1,599,671	$ 472,408
Current liabilities	$ 145,006	$ 75,004
Owner's equity	1,454,665	397,404
Total liabilities and owner's equity	$ 1,599,671	$ 472,408
Revenues	$ 56,888	$ 3,124
Operating income (loss)	4,955	(1,654)
Net income (loss)	5,125	(1,568)

Although Cardinal and UEO had combined net income of $5.1 million for 2013, UEO incurred a net loss of $8.7 million and, as we own 21% of UEO, our proportionate share of UEO's net loss was greater than our 9% proportionate share of Cardinal's net income of $13.8 million. Accordingly, we recognized a combined loss from Cardinal and UEO.

As of December 31, 2013 and 2012, the excess of our investment over our equity in Cardinal and UEO is $8.2 million and $0.9 million, respectively.

NOTE 7. 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 the market price of oil, natural gas and natural gas liquids and interest rates. We use derivatives to reduce our risk of volatility in the prices of oil, natural gas and natural gas liquids 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 earnings as "(Loss) gain on derivatives, net" in our consolidated statements of operations.

As of December 31, 2013, we had entered into commodity contracts with the following terms:

Period Covered	Hedged Volume	Weighted Average Fixed Price
Oil (MBbls):		
Swaps – 2014	1,517.7	$ 91.19
Swaps – 2015	730.0	90.09
Natural Gas (MmmBtus):		
Swaps – 2014	39,712.0	4.70
Swaps – 2015	36,317.5	4.94
Swaps – 2016	10,980.0	4.17

As of December 31, 2013, we had also entered into interest rate swaps with the following terms:

Period Covered	Notional Amount	Floating Rate	Fixed Rate
January 2014 – July 2015	$ 110,000	1 Month LIBOR	3.315%

The following table sets forth the fair values and classification of our outstanding derivatives:

	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Assets Presented in the Consolidated Balance Sheets
Derivatives:			
As of December 31, 2013:			
Derivative asset	$ 24,950	$ (11,407)	$ 13,543
Long–term derivative asset	30,903	(1,815)	29,088
Total	$ 55,853	$ (13,222)	$ 42,631
As of December 31, 2012:			
Derivative asset	$ 44,173	$ (3,402)	$ 40,771
Long–term derivative asset	50,692	(4,853)	45,839
Total	$ 94,865	$ (8,255)	$ 86,610

	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Liabilities Presented in the Consolidated Balance Sheets
Derivatives:			
As of December 31, 2013:			
Derivative liability	$ 14,755	$ (11,407)	$ 3,348
Long–term derivative liability	1,815	(1,815)	–
Total	$ 16,570	$ (13,222)	$ 3,348
As of December 31, 2012:			
Derivative liability	$ 3,402	$ (3,402)	$ –
Long–term derivative liability	4,853	(4,853)	–
Total	$ 8,255	$ (8,255)	$ –

We have entered into master netting arrangements with our counterparties. The amounts above are presented on a net basis in our consolidated balance sheets when such amounts are with the same counterparty. In addition, we have recorded accounts payable and receivable balances related to our settled derivatives that are subject to our master netting agreements. These amounts are not included in the above table; however, under our master netting agreements, we have the right to offset these positions against our forward exposure related to outstanding derivatives.

Should our credit facility become due and payable because of an event of default, our derivatives that are in a net liability position could also become due and payable. We could also be required to post cash collateral related to these derivatives under certain circumstances. As of December 31, 2013 and 2012, we were not required to post any collateral nor did we hold any collateral associated with our derivatives.

NOTE 8. FAIR VALUE MEASUREMENTS

Recurring Basis

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 Measurements at the End of the Reporting Period		
	Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
As of December 31, 2013:				
Assets – Commodity contracts	$ 55,853	$ –	$ 55,853	$ –
Liabilities:				
Commodity contracts	$ 11,560	$ –	$ 11,560	$ –
Interest rate swaps	5,010	–	5,010	–
Total	$ 16,570	$ –	$ 16,570	$ –
As of December 31, 2012:				
Assets – Commodity contracts	$ 94,865	$ –	$ 94,865	$ –
Liabilities – Interest rate swaps	$ 8,255	$ –	$ 8,255	$ –

Our derivatives consist of over–the–counter ("OTC") contracts which are not traded on a public exchange. 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 using the income approach using inputs such as 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, such as forward LIBOR curves. Our estimates of fair value have been determined at discrete points in time based on relevant market data. There were no changes in valuation techniques or related inputs in 2013.

Nonrecurring Basis

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 nonrecurring basis:

		Fair Value Measurements at the End of the Reporting Period			
	Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Losses
Year ending December 31:					
2013:					
Long–lived assets held and used	$ 55,163	$ –	$ –	$ 55,163	$ 76,342
Long–lived assets held for sale	8,012	–	8,012	–	514
	$ 63,175	$ –	$ 8,012	$ 55,163	$ 76,856
2012:					
Long–lived assets held and used	$ 34,214	$ –	$ –	$ 34,214	$ 31,876
Long–lived assets held for sale	6,014	–	6,014	–	491
	$ 40,228	$ –	$ 6,014	$ 34,214	$ 32,367
2011:					
Long–lived assets held for sale	$ 15,784	$ –	$ 15,784	$ –	$ 10,399

Long–lived Assets Held and Used

In 2013, oil and natural gas properties with an aggregate carrying amount of $131.5 million were written down to their aggregate fair value of $55.2 million, resulting in an aggregate impairment charge of $76.3 million. This impairment charge was included in earnings for 2013. In 2012, oil and natural gas properties with an aggregate carrying amount of $66.1 million were written down to their aggregate fair value of $34.2 million, resulting in an aggregate impairment charge of $31.9 million. This impairment charge was included in earnings for 2012.

The fair values were determined using the income approach and were based on the expected present value of the future net cash flows from proved reserves. Significant Level 3 assumptions associated with the calculation of discounted cash flows used in the impairment analysis included estimates of future prices, production costs, development expenditures, anticipated production of proved reserves, appropriate risk–adjusted discount rates and other relevant data.

Long–lived Assets Held for Sale

In 2013, we incurred an impairment charge of $0.5 million to write down assets held for sale to their fair market value of $8.0 million. This impairment charge was included in earnings for 2013. In 2012, we incurred additional impairment charges of $0.5 million to write down assets held for sale to their fair value of $6.0 million. These impairment charges were included in earnings for 2012. At various times during 2011, oil and natural gas properties with an aggregate carrying amount of $26.2 million were written down to their aggregate fair value of $15.8 million, resulting in impairment charges of $10.4 million. These impairment charges were included in earnings for 2011.

The fair values were determined using Level 2 inputs consisting of the mutually agreed upon selling price we received upon the sale of these oil and natural gas properties.

As of December 31, 2013, we have $8.0 million of oil and natural gas properties and $2.2 million of ARO classified as assets held for sale and liabilities held for sale, respectively in our consolidated balance sheets.

Financial Instruments

The estimated fair values of our financial instruments have been determined at discrete points in time based on relevant market information. 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 above).

The carrying value of debt outstanding under our credit facility approximates fair value because the credit facility's variable interest rate resets frequently and approximates current market rates available to us. As of December 31, 2013 and December 31, 2012, the estimated fair value of our senior notes due 2019 was $504.7 million and $531.2 million, respectively, which differs from the carrying value of $499.3 million and $499.2 million, respectively. The fair value of the senior notes due 2019 was determined using Level 2 inputs.

NOTE 9. ASSET RETIREMENT OBLIGATIONS

The changes in the aggregate ARO are as follows:

Balance as of December 31, 2011	$ 93,225
Liabilities incurred and assumed in acquisitions	5,344
Accretion expense	5,116
Revisions in estimated cash flows	7,637
Settlements and divestitures	(6,638)
Balance as of December 31, 2012	104,684
Liabilities incurred and assumed in acquisitions	1,852
Accretion expense	4,925
Revisions in estimated cash flows	(6,704)
Settlements and divestitures	(1,584)
Balance as of December 31, 2013	$ 103,173

As of December 31, 2013 and 2012, $1.9 million and $2.0 million, respectively, of our ARO is classified as current and is included in "Accounts payable and accrued liabilities" in our consolidated balance sheets. In addition, as of December 31, 2013, $2.2 million of our ARO is included in "Liabilities related to assets held for sale" in our consolidated balance sheets.

NOTE 10. LONG–TERM DEBT

Credit Facility

As of December 31, 2013, we have a $1.0 billion credit facility that expires in April 2016. Borrowings under the facility are secured by a first priority lien on substantially all of our oil and natural gas properties. 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 $100.0 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 senior secured debt to earnings plus interest expense, taxes, depreciation, depletion and amortization expense and exploration expense of no greater than 3.5 to 1.0. As of December 31, 2013, we were in compliance with these financial covenants.

The facility does not require any repayments of amounts outstanding until it expires in April 2016. 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 3.09% and 3.53% at December 31, 2013 and 2012, respectively).

Borrowings under the facility may not exceed a "borrowing base" determined by the lenders under the facility based on our oil and natural gas reserves. As of December 31, 2013, the borrowing base under the facility was $730.0 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.

We had $481.0 million and $360.0 million outstanding under the facility at December 31, 2013 and 2012, respectively.

8.0% Senior Notes due 2019

On March 22, 2011, we issued $300.0 million in aggregate principal amount of 8.0% senior unsecured notes due 2019 (the "Notes"). We received net proceeds of $291.5 million, after deducting $8.5 million for underwriters' discounts and payment of offering expenses.

On March 13, 2012, we issued an additional $200.0 million in aggregate principal amount of the Notes at an offering price equal to 103% of par, or $206.0 million, plus $6.6 million of accrued interest from October 15, 2011 pursuant to the same indenture under which our existing $300.0 million of 8.0% senior unsecured notes due 2019 were issued. We received proceeds of $201.9 million after deducting $4.1 million for underwriters' discounts and payment of offering expenses.

The Notes were issued under an indenture dated March 22, 2011, (the "Indenture"), mature April 15, 2019, and bear interest at 8.0%. Interest is payable semi–annually beginning October 15, 2011. The Notes are general unsecured obligations and are effectively junior in right of payment to any of our secured indebtedness to the extent of the value of the collateral securing such indebtedness.

The Notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis, by all of our existing subsidiaries other than EV Energy Finance Corp. ("Finance"), which is a co–issuer of the Notes. Neither the Parent nor Finance have independent assets or operations apart from the assets and operations of our subsidiaries.

The Indenture provides that, prior to April 15, 2014, we may redeem up to 35% of the aggregate principal amount of the Notes with the net proceeds of a public or private equity offering at a redemption price of 108.0% of the principal amount redeemed, plus accrued and unpaid interest, provided that:

- at least 65% of the aggregate principal amount of Notes issued under the Indenture remains outstanding immediately after the occurrence of such redemption; and
- the redemption occurs within 180 days of the date of the closing of such public or private equity offering.

On and after April 15, 2015, we may redeem all or a part of the Notes, at the redemption prices (expressed as percentages of principal amount) set forth below, plus accrued and unpaid interest, if any, on the Notes to be redeemed to the applicable redemption date, if redeemed during the twelve–month period beginning on April 15 of the years indicated below:

Year	Percentage
2015	104.0%
2016	102.0%
2017 and thereafter	100.0%

Prior to April 15, 2015, we may redeem all or part of the Notes at a redemption price equal to the sum of:

- the principal amount thereof, plus
- the Make Whole Premium (as defined in the Indenture) at the redemption date, plus accrued and unpaid interest, if any, to the redemption date.

The Indenture also provides that, if a change of control (as defined in the Indenture) occurs, the holders have a right to require us to repurchase all or part of the Notes at a redemption price equal to 101%, plus accrued and unpaid interest.

The Indenture contains covenants that, among other things, limit our ability to: (i) pay distributions on, purchase or redeem our common units or redeem our subordinated debt; (ii) make investments; (iii) incur or guarantee additional indebtedness or issue certain types of equity securities; (iv) create certain liens; (v) sell assets; (vi) consolidate, merge or transfer all or substantially all of our assets; (vii) enter into intercompany agreements that restrict distributions or other payments from our restricted subsidiaries to us; (viii) engage in transactions with affiliates; and (ix) create unrestricted subsidiaries.

The aggregate carrying amount of the Notes was $499.3 million and $499.2 million at December 31, 2013 and December 31, 2012, respectively.

NOTE 11. 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 effect on our consolidated financial statements, and no amounts have been accrued at December 31, 2013 and 2012.

As of December 31, 2013, we expect our aggregate commitment to fund the construction activities for Cardinal and UEO to be between $140.0 million and $160.0 million for 2014 and 2015.

We have entered into a firm agreement for the future transportation and processing of natural gas. We are obligated to transport minimum daily natural gas volumes. As of December 31, 2013, our future minimum transportation fees under this agreement are as follows for the years ended December 31:

2014	$	618
2015		619
2016		618
2017		619
2018		618
Thereafter		2,268
	$	5,360

NOTE 12. OWNERS' EQUITY

Units Outstanding

At December 31, 2013, owner's equity consists of 48,349,080 common units outstanding (including 4,101,541 common units held by our executive officers and directors), collectively representing a 98% limited partnership interest in us, and a 2% general partnership interest.

Equity Offerings

In October 2013, we closed a public offering of 5.75 million common units at an offering price of $36.86 per common unit. We received net proceeds of $208.5 million, including a contribution of $4.2 million by our general partner to maintain its 2% interest in us.

In February 2012, we closed a public offering of 4.025 million of our common units at an offering price of $67.95 per common unit. We received net proceeds of $267.9 million, including a contribution of $5.4 million by our general partner to maintain its 2% interest in us.

In March 2011, we closed a public offering of 3.45 million of our common units at an offering price of $44.42 per common unit. We received net proceeds of $149.8 million, including a contribution of $3.0 million by our general partner to maintain its 2% interest in us.

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.

Class B Units

In December 2011, our general partner notified us that it had made an incentive distribution rights (“IDR”) reset election as defined in our partnership agreements. Under the IDR reset election, our general partner relinquished its right to receive incentive distribution payments based on the minimum quarterly and target cash distribution levels set at the time of our public offering. The minimum quarterly distribution was increased from $0.40 to $0.7615 and the levels at which the IDRs participate in distributions were reset at higher amounts based on current common unit distribution rates and a formula in the partnership agreement. In connection with resetting the minimum quarterly and target cash distribution levels, our general partner received 3.9 million Class B units. In December 2012, we issued 3.9 million common units when the holders of our Class B units elected to convert their Class B units into common units on a one–for–one basis.

The Class B units had limited voting rights as set forth in our partnership agreement. Prior to converting into common units, each Class B unit was entitled to the same distributions and voting rights as a common unit.

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

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 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 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:

	Total Quarterly Distributions Target Amount	Marginal Percentage Interest in Distributions Limited Partner	General Partner
Minimum quarterly distribution	$0.7615	98%	2%
First target distribution	Up to $0.875725	98%	2%
Second target distribution	Above $0.875725, up to $0.951875	85%	15%
Thereafter	Above $0.951875	75%	25%

The following sets forth the distributions we paid during the years ended December 31, 2013 and 2012:

Date Paid	Period Covered	Distribution per Unit	Total Distribution
February 14, 2013	October 1, 2012 – December 31, 2012	$ 0.767	$ 33,838
May 15, 2013	January 1, 2013 – March 31, 2013	0.768	33,883
August 14, 2013	April 1, 2013 – June 30, 2013	0.769	33,925
November 14, 2013	July 1, 2013 – September 30, 2013	0.770	38,480
			$ 140,126
February 14, 2012	October 1, 2011 – December 31, 2011	$ 0.763	$ 29,815
May 15, 2012	January 1, 2012 – March 31, 2012	0.764	32,994
August 14 2012	April 1, 2012 – June 30, 2012	0.765	33,036
November 14, 2012	July 1, 2012 – September 30, 2012	0.766	33,079
			$ 128,924

On January 31, 2014, the board of directors of EV Management declared a $0.771 per unit distribution for the fourth quarter of 2013 on all common units. The distribution was paid on February 14, 2014 to unitholders of record at the close of business on February 10, 2014. The aggregate amount of the distribution was $38.7 million.

NOTE 13. NET (LOSS) INCOME PER LIMITED PARTNER UNIT

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

	2013	2012	2011
Net (loss) income	$ (76,227)	$ (16,349)	$ 102,641
Incentive distribution rights	–	–	(8,833)
General partner's 2% interest in net (loss) income	1,525	327	(2,053)
Net (loss) income attributable to participating securities	(2,006)	–	–
Limited partners' interest in net (loss) income	$ (76,708)	$ (16,022)	$ 91,755
Weighted average limited partner units outstanding:			
Common units	43,691	38,156	33,532
Class B units	–	3,662	212
Performance units	–	134	151
Denominator for basic net (loss) income per limited partner unit	43,691	41,952	33,895
Dilutive phantom units (1)	–	–	288
Total	43,691	41,952	34,183
Net (loss) income per limited partner unit:			
Basic	$ (1.76)	$ (0.38)	$ 2.71
Diluted	$ (1.76)	$ (0.38)	$ 2.68

(1) Units totaling 0.2 million and 0.8 million units were not included in the computation of diluted net (loss) income per limited partner unit for 2013 and 2012, respectively, because the effect would have been anti-dilutive.

NOTE 14. RELATED PARTY TRANSACTIONS

Pursuant to our omnibus agreement with EnerVest, we paid EnerVest $10.0 million, $13.1 million and $10.9 million in 2013, 2012 and 2011, 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 2013, 2012 and 2011, we reimbursed EnerVest approximately $17.1 million, $17.5 million and $15.5 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, natural gas and natural gas liquids sales and distributes them to us and other working interest owners.

In 2011, we and certain institutional partnerships managed by EnerVest carved out 7.5% overriding royalty interests ("ORRI") from certain acres in Ohio (the "Underlying Properties"), which we believe may be prospective for the Utica Shale, and contributed the ORRI to a newly formed limited partnership. EnerVest is the general partner of this partnership. The ORRI will entitle the partnership to an average approximate 5.64% of the gross revenues from the Underlying Properties. We own a 48% limited partner interest in the partnership and account for our investment using the equity method of accounting. We recognized $0.2 million and $0.1 million of income from unconsolidated affiliates in 2013 and 2012, respectively, and we received $0.2 million of distributions in 2013.

In August 2011, followed by a second closing in October 2011, we acquired oil and natural gas properties in the Appalachian Basin from certain institutional partnerships managed by EnerVest for $31.1 million (see Note 4).

NOTE 15. OTHER SUPPLEMENTAL INFORMATION

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

	2013	2012	2011
Supplemental cash flows information:			
Cash paid for interest, net of capitalized interest of $7,276 and $906 at December 31, 2013 and 2012, respectively	$ 45,355	$ 47,903	$ 21,880
Cash paid for income taxes	325	340	265
Non–cash transactions:			
Costs for additions to oil and natural gas properties in accounts payable and accrued liabilities	19,450	13,951	12,046
Purchase price adjustment in accounts receivable	–	7,969	–
Cost for acquisition of oil and natural gas properties in accounts payable and accrued liabilities	–	–	423

Accounts payable and accrued liabilities consisted of the following as of December 31:

	2013	2012
Costs for additions to oil and natural gas properties	$ 19,450	$ 13,951
Lease operating expenses	7,793	7,309
Interest	8,701	8,566
Production and ad valorem taxes	4,862	4,379
General and administrative expenses	2,082	2,596
Current portion of ARO	1,885	1,977
Derivative settlements	1,443	364
Other	660	1,029
Total	$ 46,876	$ 40,171

NOTE 16. QUARTERLY DATA (UNAUDITED)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2013				
Revenues	$ 73,702	$ 81,602	$ 81,414	$ 78,594
Gross profit [1]	43,949	51,510	51,526	49,144
Net (loss) income	(46,581)	32,854	(12,314)	(50,186)
Net (loss) income per limited partner unit:				
Basic	$ (1.08)	$ 0.74	$ (0.29)	$ (1.06)
Diluted	$ (1.08)	$ 0.74	$ (0.29)	$ (1.06)
2012				
Revenues	$ 77,731	$ 63,552	$ 68,701	$ 75,496
Gross profit [1]	45,204	35,676	40,631	46,853
Net income (loss)	28,593	14,956	(50,019)	(9,879)
Net income (loss) per limited partner unit:				
Basic	$ 0.69	$ 0.35	$ (1.15)	$ (0.23)
Diluted	$ 0.69	$ 0.34	$ (1.15)	$ (0.23)

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

NOTE 17. SEGMENT INFORMATION

As a result of our decision to allocate resources to our midstream business, we now have two reportable segments: exploration and production and midstream. Our exploration and production segment is responsible for the acquisition, development and production of our oil and natural gas properties. Our midstream segment, which consists of Cardinal and UEO, is accounted for using the equity method of accounting and is engaged in the construction and operation of natural gas processing, natural gas liquids fractionation, connecting pipeline infrastructure and gathering systems to serve production in the Utica Shale area in Ohio. All of our operations are located in the United States.

Management evaluates the performance of our segments based on segment profits, which include segment revenues and direct segment costs and expenses. Segment profit excludes items such as asset retirement obligations accretion expense, depreciation, depletion and amortization, general and administrative expenses, impairment of oil and natural gas properties, (loss) gain on derivatives, interest expense and other income or expense.

We have not presented any segment information for 2011 as we did not begin investing in Cardinal and UEO until 2012.

Summarized financial information for our operating segments is shown below:

	Exploration and Production	Midstream	Consolidated Total
Year ended December 31, 2013:			
Total revenues	$ 315,312	$ –	$ 315,312
Segment profit	193,749	–	193,749
Equity in (loss) income of unconsolidated affiliates	259	(603)	(344)
Year ended December 31, 2012:			
Total revenues	285,480	–	285,480
Segment profit	161,593	–	161,593
Equity in (loss) income of unconsolidated affiliates	156	(138)	18
As of December 31, 2013:			
Capital expenditures	175,870	–	175,870
Total assets	1,950,300	254,683	2,204,983
As of December 31, 2012:			
Capital expenditures	249,048	–	249,048
Total assets	2,031,228	34,186	2,065,414

The following table reconciles the segment profits reported above to loss before income taxes and (loss) income from unconsolidated affiliates for the years ended December 31:

	2013	2012
Segment profit	$ 193,749	$ 161,593
Asset retirement obligations accretion expense	(4,925)	(5,116)
Depreciation, depletion and amortization	(113,818)	(113,381)
General and administrative expenses	(40,677)	(42,682)
Impairment of oil and natural gas properties	(85,341)	(34,453)
Gain on sales of oil and natural gas properties	41,309	–
(Loss) gain on derivatives, net	(17,262)	66,734
Interest expense	(49,062)	(48,689)
Other income	277	705
Loss before income taxes and equity in (loss) income from unconsolidated affiliates	$ (75,750)	$ (15,289)

NOTE 18. 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:

	2013	2012
Proved oil and natural gas properties	$ 2,265,069	$ 2,131,616
Unproved oil and natural gas properties	133,763	133,480
	2,398,832	2,265,096
Accumulated depreciation, depletion and amortization	(569,770)	(389,206)
Net capitalized costs	$ 1,829,062	$ 1,875,890

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

	2013	2012	2011
Acquisition of oil and natural gas properties:			
Proved	$ 59,602	$ 36,834	$ 408,633
Unproved	6,018	75,229	43,947
Exploration costs	1,764	5,671	6,112
Development costs	108,486	131,674	77,961
Total	$ 175,870	$ 249,408	$ 536,653

NOTE 19. 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 these estimates. The estimates of our proved reserves as of December 31, 2013, 2012 and 2011 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, 2010	12,888	575,202	27,468	817,340
Revisions of previous estimates	718	(20,204)	(123)	(16,631)
Purchases of minerals in place	2,506	277,595	14,405	379,060
Extensions and discoveries	595	6,352	319	11,839
Production	(891)	(29,247)	(1,096)	(41,169)
Sales of minerals in place	(749)	(1,017)	(89)	(6,050)
As of December 31, 2011	15,067	808,681	40,884	1,144,389
Revisions of previous estimates [4]	(1,489)	(210,452)	(5,688)	(253,513)
Purchases of minerals in place	236	25,532	559	30,301
Extensions and discoveries [5]	1,011	30,429	1,859	47,649
Production	(1,110)	(42,536)	(1,742)	(59,647)
Sales of minerals in place	(207)	(2,108)	(193)	(4,510)
As of December 31, 2012	13,508	609,546	35,679	904,669
Revisions of previous estimates	(760)	36,214	4,835	60,663
Purchases of minerals in place	21	67,291	496	70,395
Extensions and discoveries [6]	1,342	149,502	10,093	218,112
Production	(1,027)	(42,651)	(2,146)	(61,690)
Sales of minerals in place	–	(222)	(55)	(555)
As of December 31, 2013	13,084	819,680	48,902	1,191,594
Proved developed reserves:				
December 31, 2010	10,923	416,770	15,954	578,032
December 31, 2011	11,675	557,489	25,359	779,693
December 31, 2012	11,153	473,223	24,832	689,133
December 31, 2013	10,443	578,274	29,056	815,268
Proved undeveloped reserves:				
December 31, 2010	1,965	158,432	11,514	239,308
December 31, 2011	3,392	251,192	15,525	364,696
December 31, 2012	2,355	136,323	10,847	215,536
December 31, 2013	2,641	241,406	19,846	376,326

(1) Thousands of barrels.

(2) Million cubic feet.

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

(4) Revisions were primarily attributable to decreased prices used in estimating our reserves (269.9 Bcfe) offset by positive development and production history (16.4 Bcfe).

(5) Extensions and discoveries were primarily associated with drilling success in the Barnett Shale (39.0 Bcfe) and the Appalachian Basin (3.1 Bcfe).

(6) Extensions and discoveries were primarily associated with drilling success in the Barnett Shale (177.1 Bcfe).

NOTE 20. 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:

	2013	2012	2011
Future cash inflows	$ 4,998,790	$ 4,005,432	$ 6,334,354
Future production and development costs	(2,509,542)	(1,971,099)	(2,873,899)
Future income tax expenses	(22,091)	(16,473)	(26,131)
Future net cash flows	2,467,157	2,017,860	3,434,324
10% annual discount for estimated timing of cash flows	(1,427,372)	(1,150,928)	(2,028,193)
Standardized measure of discounted future net cash flows	$ 1,039,785	$ 866,932	$ 1,406,131

As specified by the SEC, the prices for oil, natural gas and natural gas liquids used in this calculation were the average prices during the year determined using the price on the first day of each month, except for volumes subject to fixed price contracts. The prices utilized in calculating our total estimated proved reserves at December 31, 2013, 2012 and 2011 were $96.78 per Bbl of oil, $3.666 per MMBtu of natural gas; $94.71 per Bbl of oil, $2.757 per MMBtu of natural gas; and $96.19 per Bbl of oil and $4.12 per MMBtu of natural gas, respectively. We do not include our commodity 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:

	2013	2012	2011
Standardized measure at beginning of period	$ 866,932	$ 1,406,131	$ 1,020,235
Sales and transfers of oil, natural gas and natural gas liquids produced, net of production costs	(194,942)	(167,233)	(170,705)
Net changes in prices and production costs	(1,264)	(292,849)	50,201
Extensions, discoveries and improved recovery, less related costs	113,714	62,367	36,999
Development costs incurred during the period	17,762	37,501	4,295
Revisions and other	53,427	(313,955)	(20,888)
Accretion of 10% timing discount	87,433	141,723	102,649
Changes in income taxes	(2,218)	3,697	(4,842)
Changes in estimated future development costs	1,692	1,319	10,544
Changes in timing and other	55,966	(35,046)	47,215
Purchase of minerals in place	41,810	32,906	340,367
Sales of minerals in place	(527)	(9,629)	(9,939)
Standardized measure of discounted future net cash flows	$ 1,039,785	$ 866,932	$ 1,406,131

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, 2013 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, 2013. 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, 2013 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, 2013, EV Investors is owned 60% by EnerVest and 40% 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 board of directors has no policy regarding the separation of the positions of chief executive officer and chairman. We do not have a lead independent director. All of our directors are appointed by EnerVest, and EnCap is entitled to designate 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 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. 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 Flory, are employees of EV Management and devote all of their time to our business and affairs. In January 2014, Mr. Flory was appointed controller of EV Management, following our former controller's retirement.

We estimate that Messrs. Walker, Houser and Flory devote approximately 25%, 50% and 35%, respectively, of their 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 2013, we paid EnerVest $10.0 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 14, 2014 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	68	Executive Chairman and Director
Mark A. Houser	52	President, Chief Executive Officer and Director
Michael E. Mercer	55	Senior Vice President and Chief Financial Officer
Ronald J. Gajdica	53	Senior Vice President of Acquisitions
Ryan J. Flory	37	Controller
Victor Burk (1) (2)	64	Director
James R. Larson (1)	64	Director
George Lindahl III (1) (2)	67	Director
Gary R. Petersen (2)	67	Director

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

(2) Member of the compensation committee.

John B. Walker has served as our Executive Chairman since January 2012 and has been a director since 2006. Prior to serving as Executive Vice Chairman, he served as our 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 and is a member of the board of directors of the general partner of PetroLogistics, L.P. 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 and, in January 2012, he was appointed by Gov. Rick Perry to serve on the Board of Regents. 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 and Chief Executive Officer since January 2012. Prior to that, he served as our President and Chief Operating Officer 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 as the chairman of the industry board of the Texas A&M University Department of Petroleum Engineering and is a member of the Society of Petroleum Engineers. Mr. Houser was recently inducted into the Texas A&M Petroleum Engineering Academy of Distinguished Graduates. Additionally, he serves on the board of directors for the Methodist Hospital System and on the administrative board of Chapelwood United Methodist Church.

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 12 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 in the Houston office of Scotia Waterous, a global leader in advisory services for oil and natural gas acquisitions and divestitures. He was responsible for the Mergers, Acquisitions and Divestment technical advisory team for the U.S. and Latin America, as well as IT, Graphics and Administrative functions. 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 (ranked first in class) of Science degrees in Petroleum Engineering from Texas A&M University, and a Ph.D. in Petroleum Engineering from Stanford University. He is a member of the Society of Petroleum Engineers, spent 13 years as an SPE Technical Editor, is a registered Professional Engineer in the state of Texas and has authored several technical papers.

Ryan J. Flory has served as Controller of EV Management since February 2014 and as Vice President and Controller of EnerVest, Ltd. since January 2014. Prior to that, Mr. Flory served as Corporate Controller of EnerVest, Ltd. since 2013. From 2005 to 2013, he served as Manager of Financial Reporting for EnerVest, Ltd, and from 2003 to 2005, he worked for Belden & Blake Corporation where he held various management and supervisory positions. Mr. Flory began his career with Deloitte & Touche. He holds a Bachelor’s of Business Administration, Accounting, from Kent State University and is a CPA and a member of the American Institute of Certified Public Accountants.

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 PAA GP Holdings, LLC, the general partner of Plains GP Holding, L.P. (NYSE: PAGP). 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. Mr. Larson also serves on the board of Compressco Partners GP Inc., general partner of Compressco Partners, L.P. 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 2007 to the present, Mr. Lindahl manages GL III Investments. 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. Mr. Peterson is a Managing Partner and co–founder of EnCap Investments L.P., an investment manager and leading provider of private equity capital to the upstream and midstream sectors of the oil and natural gas industry. The firm has raised 17 institutional oil and natural gas investment funds totaling approximately $18 billion and currently manages capital on behalf of more than 250 U.S. and institutional investors. Prior to the formation of EnCap Investments in 1988, Mr. Petersen was a Senior Vice President and Manager of the Corporate Finance Division of the Energy Banking Group for Republic Bank Corporation from 1985 to 1988. His duties and responsibilities included mergers and acquisitions, financial advisory services and institutional fund raising activities for the energy industry. Prior to his position at Republic Bank, Mr. Petersen was an Executive Vice President and a member of the board of directors of Nicklos Oil & Gas Company in Houston from 1979 to 1984. Previously, Mr. Petersen was a Group Vice President in the Petroleum and Minerals Division of Republic Bank Dallas. He served from 1970 to 1971 in the U.S. Army in Washington D.C. as a First Lieutenant in the Finance Corps and as an Army Officer in the Army Security Agency. Mr. Petersen is a distinguished Alumni of Texas Tech University and holds B.B.A. and M.B.A. degrees in Finance. He has also done post-graduate work at American University and the Stonier Graduate School of Banking at Rutgers University. 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. (NYSE: PAA) and Canacol Energy Ltd. (TSXV: CNE). He is a member of the Independent Petroleum Association of America, the Houston Producers' Forum and the Petroleum Club of Houston. He is also a member and past Chairman of Chapelwood United Methodist Church, Chairman of the Memorial Hermann Healthcare Foundation and a past Chairman of the Council on Alcohol and Drugs in Houston. Mr. Petersen brings to our board the expertise he has acquired from being involved in the energy sector for more than 30 years, including extensive knowledge of the energy sector's various cycles, as well as the current market and industry knowledge that comes with management of approximately $11 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 and Burk 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 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 2013, representatives of our independent registered public accounting firm 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 our management or board of directors believes may involve conflicts of interest. 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 2013, the board of directors had six regularly scheduled and special meetings, the audit committee had four meetings, the compensation committee had one meeting and the conflicts committee had five 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, we believe that during 2013, 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), except that Mr. Lindhal reported a gift of 20,000 common units to a trust for one of his children late on a Form 5.

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 and Houser 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. 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 was reviewed and approved by our compensation committee, and we reimburse EnerVest for these cash bonuses. In addition, Messrs. Walker and Houser continue to participate in the Plan.

Our compensation committee discusses with EnerVest the philosophy used by EnerVest in setting the salaries and bonus compensation for its employees who perform services for us under the omnibus agreement. However, except for the bonus payments noted in the previous paragraph, the compensation committee has no role in determining the base salary and short–term and long–term incentive compensation paid to EnerVest employees. 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 Houser's cash bonus charged to us, we do not directly reimburse EnerVest for the costs of the compensation of Messrs. Walker and Houser and our compensation committee does not oversee their annual compensation. Awards made to Messrs. Walker and Houser 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 takes into account 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, natural gas and natural gas liquids production and reserves; level of job responsibility; and tenure.

Compensation Consultant

Our compensation committee did not retain an independent compensation consultant. Since 2010, EnerVest has retained Longnecker & Associates to provide compensation advice and data to EnerVest regarding its employees, including our executive officers. In general, the role of the outside compensation consultant is to assist EnerVest with the analysis of executive pay packages; however EnerVest is under no obligation to follow the advice or recommendations of any compensation consultant.

EnerVest provided our compensation committee with a summary of Longnecker & Associates' analysis of the compensation of EnerVest employees who perform services for us, as well as our executive officers, which the committee considered in approving the compensation of our executive officers. Like EnerVest, the compensation committee is under no obligation to follow the advice or recommendations on any compensation consultant.

Benchmarking

As part of the proposed compensation plan, our chief executive officer asked Longnecker & Associates to prepare an analysis of the compensation paid (based on survey data and proxy analysis) by a peer group composed of the following companies: Atlas Resource Partners, L.P., Bill Barrett Corp., BreitBurn Energy Partners, L.P., Carrizo Oil & Gas, Inc., Kodiak Oil & Gas Corp., Laredo Pteroleum Holdings, Inc., Legacy Reserves LP, Linn Energy, LLC, Memorial Production Partners, L.P., Oasis Petroleum, Inc., PDC Energy, Inc., QR Energy, L.P., Rosetta Resources, Inc., and Vanguard Natural Resources, LLC. The compensation committee reviews the composition of the peer group each year. Longnecker & Associates reviewed peer group and survey data and made recommendations regarding executive and director compensation.

Our management and compensation committee used information regarding peer companies to check their base salary and bonus compensation decisions for reasonableness and to benchmark with respect to base salary and long–term incentive compensation. In connection with setting base salary for 2014 and bonus and long–term equity incentive compensation for 2013, the compensation committee continued this practice.

Performance Metrics

With respect to bonus and long–term incentive awards, our compensation committee did not establish performance metrics for our executive officers for 2013 in order to remain flexible in our compensation practices. The compensation committee makes a subjective determination at the end of the fiscal year as to the appropriate compensation based on a recommendation from our chief executive officer and given their view of our 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.

While the allocation of total compensation among base salary, cash bonus and long–term incentive compensation will vary from year to year based on performance and market conditions, we generally allocate a greater portion of total compensation to long–term equity based compensation because we believe this better aligns the interests of our executives with those of our unit holders over the long term. In addition, the annual grant of phantom units under the Plan is intended to provide a longer term incentive to our key employees to focus their efforts on increasing the market price of our publicly traded common units and to increase the cash distributions we pay to our unitholders.

In 2011, EnerVest established the EnerVest Ltd. Retirement Plan (the "Retirement Plan"), a defined benefit plan under ERISA, for certain of the officers and other highly compensated employees of EnerVest and its subsidiaries. The purpose of the Retirement Plan is to provide a company funded tax–qualified plan for retirement benefits on a tax advantaged basis. Employees who are eligible to participate in the Retirement Plan receive their base salary in two forms: (i) cash compensation, subject to applicable taxes and withholdings and (ii) a fully vested annual company contribution to the Retirement Plan. Therefore, the overall level of compensation is not enhanced for the Retirement Plan participants because a portion of compensation is contributed to the Retirement Plan by the company in lieu of current cash compensation. The participants accrue a benefit based on their age, designated "allocation group," the investment yield on the Retirement Plan’s assets and other factors, subject to the limits on benefits prescribed under the Internal Revenue Code. The benefit is payable in various annuity forms or as a lump sum. All benefit election forms are actuarially equivalent, and there are no subsidies to any election.

At the time of the adoption of the Retirement Plan, EnerVest amended its 401(k) Plan with regard to EnerVest’s contributions. Under the 401(k) Plan, all employees who are eligible to participate receive a 3% "safe harbor" contribution from EnerVest. EnerVest may also make an additional discretionary "safe harbor" contribution to all employees who are entitled to participate in the 401(k) plan. In addition, under the 401(k) plan, EnerVest may make a discretionary profit sharing contribution that is allocated to participant accounts based on their designated "allocation group." The allocation groups are structured so that certain of the officers and other highly paid employees receive a profit sharing contribution that is a greater percentage of compensation than the percentage applicable to other participants.

Mr. Mercer and Dr. Gajdica participate in the Retirement Plan and received discretionary profit sharing 401(k) contributions in an allocation group which paid a higher percent of their compensation than allocated to other participants.

When setting base salary for 2014 and 2013 for Mr. Mercer and Dr. Gajdica, the total base salary ("Total Base Salary"), inclusive of the amount delivered in cash and in company contributions under the Retirement Plan, was considered. We reimburse EnerVest for any amounts contributed to the Retirement Plan and the 401(k) plan attributable to Mr. Mercer and Dr. Gajdica. In the Summary Compensation Table, the present value of benefits under the Retirement Plan are reflected under the column "Change in Pension Value and Nonqualified Deferred Compensation Earnings" and the contributions to the 401(k) plan are included under "All Other Compensation." Additional information about the Retirement Plan is set forth under "–Retirement Plan," below.

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 and appropriate incentive, 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 2013, after comparing our executives' base salaries with our peer group, and based on the recommendation of our chief executive officer, the compensation committee targeted Total Base Salary at approximately the 25th percentile of the peer group. This resulted in a Total Base Salary for Mr. Mercer of $262,253, which compares with a Total Base Salary of $254,615 for 2012. Of this amount, $84,608 represents the estimate of the amounts to be contributed to the Retirement Plan, so Mr. Mercer's salary delivered in cash for 2013 was $177,645. For 2013, the compensation committee set the Total Base Salary for Dr. Gajdica at $256,789, which compares with a Total Base Salary of $249,310 for 2012. Of this amount, $72,053 represents the estimate of the amounts to be contributed to the Retirement Plan, so Dr. Gajdica's salary delivered in cash for 2013 was $184,736.

For 2014, after comparing our executives' base salaries with our peer group, and based on the recommendation of our chief executive officer, the committee targeted Total Base Salaries for 2014 at approximately the 25th percentile of the peer group. For 2014, the compensation committee has increased the Total Base Salaries of Mr. Mercer and Dr. Gajdica by 5% and 3%, respectively, to $275,000 and $265,000, respectively. This represents a cost of living increase for both Mr. Mercer and Dr. Gajdica, and an additional increase for Mr. Mercer to align his Total Base Salary with approximately the 25th percentile of the peer group. Of the Total Base Salary amount for Mr. Mercer and Dr. Gajdica, $89,261 and $76,016, respectively, represent estimates of the amounts to be contributed to the Retirement Plan and the balance of $185,739 and $188,984 represents the portion of their salary to be delivered in cash, respectively.

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. Our compensation committee reviewed and approved a portion of the cash bonuses paid to Messrs. Walker and Houser.

Mr. Mercer's employment agreement provides that the cash bonus element of compensation will be equal to a percentage of the executive's Total Base Salary paid during each such annual period, such percentage to be established by the compensation committee in its sole discretion. Generally, for Mr. Mercer and Dr. Gajdica, our compensation committee targets between 40% and 80% of Total Base Salary for performance deemed by our compensation committee to be good and exceptional, respectively, with the possibility of no bonus for poor performance and higher for exceptional corporate or individual performance.

Our chief executive officer recommended the cash bonuses to be paid to Mr. Mercer and Dr. Gajdica. In this recommendation and the employment agreement, the compensation committee, in determining cash bonus amounts, took into account its belief that our executives' efforts directly affected our success in 2013, in particular, by contributing to our achievement of the following milestones:

- our quarterly distributions increased from $0.767 per unit to $0.770 per unit, notwithstanding a challenging commodity price environment;

- we successfully completed in a short time frame a public equity offering with $204.3 million in net proceeds to finance acquisitions and term–out bank debt and increase liquidity;
- we achieved strong operating performance within production guidance, even with reduced capital spending;
- we began the monetization process for our Utica Shale acreage, closing on sales with proceeds of $44.1 million for these acres; and
- we continued to invest in our Utica Shale midstream partnerships.

In 2013, Mr. Mercer and Dr. Gajdica each received cash bonuses of $200,000, representing 76% and 78%, respectively, of their Total Base Salaries. While the bonus amounts were not determined by benchmarking, the compensation committee noted that these amounts placed the executives slightly below the 25th percentile of cash bonus compensation of our peer group. The bonuses for both Mr. Mercer and Dr. Gajdica also reflected the committee's determination that their performances in accomplishing the milestones for 2013 described above were very strong.

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 to accept these recommendations.

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. We generally seek to allocate a greater portion of total compensation to long–term equity compensation, generally targeting at or above the 75th percentile of our peer group for such compensation, with higher amounts for performance our compensation committee views as exceptional.

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 (or the manner in which such assignments will be made), 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, all outstanding equity based awards will immediately vest. In the event of termination of a grantee's employment upon the death, disability, or termination of a grantee's employment without good reason, all outstanding equity based awards will vest effective upon the normal vesting date that coincides with, or immediately follows, the termination. 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.

The Plan permits the compensation committee to delegate its authority to grant awards, except for awards to executive officers and directors, to one of more of our executive officers.

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.

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, 2013, there are 2.2 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 in equal annual installments over a four year period beginning January 15th of the year immediately following 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. These phantom and performance unit awards entitle the recipients of the unit awards to receive, with respect to each unit subject to such award that has not either vested or been forfeited, a cash payment equal to each cash distribution per units made by us on our units promptly following each such distribution by us to our unitholders.

Phantom Units – Mr. Mercer and Dr. Gajdica were each granted 20,000 phantom units in December 2013. These phantom units vest as described above over a four year period. These awards were recommended to our compensation committee by our chief executive officer based on his 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, noting that our peers generally provide for a three year vesting period. In determining final grant amounts, the committee also took into account the leadership roles of Mr. Mercer and Dr. Gajdica in causing us to achieve the milestones described above. The phantom units granted to Mr. Mercer were slightly below the 75th percentile of the peer group and the phantom units granted to Dr. Gajdica were slightly above the 75th percentile of the peer group.

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 considered the peer group review. Accordingly, Messrs. Walker and Houser were each granted 21,000 phantom units, respectively, in December 2013. The 2013 awards put Mr. Walker at just below the 75th percentile and Mr. Houser at just below the 50th percentile. The value of the phantom units granted to Messrs. Walker and Houser are deducted in calculating the omnibus fee we pay to EnerVest.

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, accidental death and dismemberment coverage for employees, a company sponsored cafeteria plan, a 401(k) employee savings and investment plan, and a defined benefit plan.

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, 2013, our annual distribution per common unit has increased slightly notwithstanding a challenging commodity price environment and the compound annual total rate of return for that period was approximately 11%.

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.

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 effect 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 February 14, 2014, our named executive officers beneficially owned in the aggregate approximately 8.6% 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

If an executive is entitled to nonqualified deferred compensation benefits that are subject to Internal Revenue Code 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 penalty tax of 20% of the benefit includible in income.

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 Lindahl 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. Our compensation committee approved, and we reimbursed EnerVest for cash bonuses paid to Messrs. Walker and Houser in 2013, 2012 and 2011 and listed in the table below. Messrs. Walker and Houser are compensated by EnerVest. We pay EnerVest a fee under the omnibus agreement, but, other than the cash bonuses listed in the table below, we do not directly reimburse EnerVest for the costs of their salaries and bonuses.

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.

Name and Principal Position	Year	Salary	Bonus (1)	Unit Awards (2)	Change in Pension Value and Nonqualified Deferred Compensation Earnings (3)	All Other Compensation (4)	Total
John B. Walker	2013	$ –	$ 150,000	$ 670,320	–	$ 266,670	$ 1,086,990
Executive Chairman	2012	–	150,000	1,649,760	–	340,203	2,139,963
	2011	–	150,000	4,799,250	–	349,853	5,299,103
Mark A. Houser	2013	–	150,000	670,320	–	240,541	1,060,861
President, Chief	2012	–	150,000	1,649,760	–	299,302	2,099,062
Executive Officer	2011	–	150,000	3,518,850	–	324,749	3,993,599
Michael E. Mercer	2013	177,645	200,000	638,400	108,584	235,262	1,359,891
Senior Vice President,	2012	174,418	200,000	1,178,400	88,173	325,220	1,966,211
Chief Financial Officer	2011	172,647	200,000	3,006,690	76,016	349,699	3,805,052
Ronald J. Gajdica	2013	184,736	200,000	638,400	92,470	222,551	1,338,157
Senior Vice President	2012	181,013	200,000	1,178,400	75,090	244,183	1,878,686
of Acquisitions	2011	178,559	175,000	2,815,080	64,736	198,301	3,431,676

(1) Represents amounts paid in December 2013, 2012 and 2011 as bonuses for services in 2013, 2012 and 2011, respectively.

(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 2013 and 2012, and the performance units and phantom units granted in 2011.

(3) Amounts in this column reflect the increase during 2013, 2012 and 2011 in the actuarial present value of the executive's accumulated benefit under the Retirement Plan. We do not provide above market rates of return (defined by SEC rules as a rate that exceeds 120% of the federal long–term rate) under the Retirement Plan.

(4) Represents cash distributions received on unvested phantom and performance units and, for Mr. Mercer and Dr. Gajdica, the amounts contributed by us to their 401(k) plans. In 2013, we contributed $33,915 and $33,500 to Mr. Mercer's and Dr. Gajdica's 401(k) plans, respectively. Any perquisites or other personal benefits received were less than $10,000.

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 2013. There were no grants of non–equity incentives or option awards.

Name	Grant Date	All Other Unit Awards: Number of Units (1)	Grant Date Fair Value of Unit Awards (2)
John B. Walker	December 2013	21,000	$ 670,320
Mark A. Houser	December 2013	21,000	670,320
Michael E. Mercer	December 2013	20,000	638,400
Ronald J. Gajdica	December 2013	20,000	638,400

(1) These phantom units vest 25% each year beginning in January 2015.

(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 2013.

Outstanding Equity Awards at Fiscal Year End

The following table sets forth certain information with respect to outstanding equity awards at December 31, 2013. 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	8,750(2)	$ 3,655,958	30,000(7)	$ 1,017,900
	27,500(3)			
	22,500(4)			
	28,000(5)			
	21,000(6)			
Mark A. Houser	7,750(2)	3,367,553	20,000(7)	678,600
	23,750(3)			
	18,750(4)			
	28,000(5)			
	21,000(6)			
Michael E. Mercer	6,750(2)	2,901,015	16,000(7)	542,880
	21,500(3)			
	17,250(4)			
	20,000(5)			
	20,000(6)			
Ronald J. Gajdica	7,500(2)	2,765,295	16,000(7)	542,880
	19,000(3)			
	15,000(4)			
	20,000(5)			
	20,000(6)			

(1) Based on the closing price of our common units on December 31, 2013 of $33.93.

(2) These phantom units vested in January 2014.

(3) One–half of these phantom units vested in January 2014, with the remaining one–half vesting in January 2015.

(4) One–third of these phantom units vested in January 2014, with one–third each vesting in January 2015 and January 2016.

(5) These phantom units vested 25% in January 2014, with 25% each vesting in January 2015, January 2016 and January 2017.

(6) These phantom units vest 25% each year beginning in January 2015.

(7) The first tranche of these performance units was earned in September 2011 and vested 25% in January 2012 and 25% in January 2013, with 25% each vesting in January 2014 and January 2015. The remaining tranches will be earned if trading in our common units on the NASDAQ Global Market closes at greater than $85 per unit for the second tranche and $100 per unit for the third tranche for three consecutive days. Once earned, the performance units vest 25% each year beginning in January 2012.

Option Exercises and Units Vested

The following table sets forth certain information with respect to phantom units and performance units vested during 2013. There were no option awards that vested.

Name	Number of Units Acquired on Vesting (#)	Value Realized on Vesting ($) (1)
John B. Walker	52,500	$ 3,083,850
Mark A. Houser	47,625	2,797,493
Michael E. Mercer	44,500	2,613,930
Ronald J. Gajdica	22,000	1,292,280

(1) Represents the aggregate dollar amount realized on the date of vesting based on the market price of our common units on the NASDAQ Global Market on January 15, 2013.

Pension Benefits

The following table sets forth certain information with respect to the Retirement Plan:

Name	Number of Years Credited Service	Present Value of Accumulated Benefit (1)	Payments During 2013	Contributions During 2013
Michael E. Mercer	3	$ 272,773	$ –	$ 84,608
Ronald J. Gajdica	3	232,296	–	72,053

(1) The present value of the accumulated benefit is based on the RP 2013 IRS Combined Static Mortality Table, the applicable interest rates under IRC Section 430(h)(2)(D) and age 62 normal retirement age. These assumptions are prescribed under ERISA and could be considered reasonable under accounting standards generally accepted in the United States.

Retirement benefits are provided through the Retirement Plan, which is a defined benefit retirement plan. The Retirement Plan provides that the ultimate lump sum value of the benefit a participant will be eligible to receive is equal to the contributions made to the Retirement Plan on the participant's behalf, adjusted by investment returns experienced during participation in the Retirement Plan. Payment of the benefit may begin on or after the participant has either terminated employment or attained age 62. Participants are always 100% vested in their benefit.

The Retirement Plan is a tax–qualified plan subject to Internal Revenue Code provisions that, as of December 31, 2013, limit recognized annual compensation to $250,000 and the annual retirement benefit to $200,000.

Nonqualified Deferred Compensation

We do not have a nonqualified deferred compensation plan.

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, 2013. In presenting this disclosure, we describe amounts earned through December 31, 2013 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, 2013, this amount would have been $355,290. 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, 2013, this amount would have been $36,685.

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, 2013, this amount would have been $355,290, representing 104 weeks of base salary, $2,901,015, representing vesting of unvested units and vesting of unearned units, and $36,685 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, 2013, the value of the awards would have been $2,901,015. 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 incentive 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. In addition, our compensation committee reviews director compensation at our peer group companies.

In 2013, directors who were not officers or employees of EV Management, EnCap or their respective affiliates received an annual retainer of $40,000, with the chairmen of the audit committee and conflicts committee receiving an additional annual fee of $10,000 and the chairman of the compensation committee receiving an additional annual fee of $5,000. 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 2,000 phantom units in December 2013. Mr. Petersen, who is not an independent director because of his affiliations with EnCap, was awarded 1,700 phantom units in December 2013. These phantom units vest 25% each year beginning in January 2015**.**

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, 2013:

Name [(1)]	Fees Earned or Paid in Cash ($)	Unit Awards [(2)] ($)	All Other Compensation [(3)] ($)	Total
Victor Burk [(4)]	$ 59,000	$ 63,840	$ 21,807	$ 144,647
James R. Larson [(4)]	58,500	63,840	21,807	144,147
George Lindahl III [(4)]	54,000	63,840	21,807	139,647
Gary R. Petersen [(4)]	–	54,264	18,635	72,899

(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 2013 computed in accordance with ASC Topic 718.

(3) Reflects the dollar amount of compensation recognized for financial statement reporting purposes for 2013 for distributions paid on the unvested phantom units.

(4) As of December 31, 2013, Messrs. Burk, Larson and Lindahl each have 9,094 equity awards outstanding and Mr. Petersen has 7,762 equity awards outstanding

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.

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

Security Ownership of Certain Beneficial Owners and Management

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 14, 2014 other than as set forth below.

The following table sets forth the beneficial ownership of our units as of February 14, 2014 held by:

- each person who is known to us to beneficially own 5% or more of our outstanding common units;
- 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
5% Beneficial Owner:		
Robert J. Raymond [2] RR Advisors LLC 3953 Maple Avenue, Suite 180 Dallas, TX 75219	3,720,386	7.7%
Piper Jaffray Companies [3] 800 Nicollet Mall, Suite 800 Minneapolis, MN 55042	3,485,195	7.2%
FMR LLC [4] 245 Summer Street Boston, MA 02210	3,259,449	6.7%
Officers and Directors:		
John B. Walker [5]	2,140,340	4.4%
Mark A. Houser [6]	805,230	1.7%
Michael E. Mercer	128,942	*
Ronald J. Gajdica	85,441	*
Ryan J. Flory	1,145	*
Victor Burk	15,343	*
James R. Larson	13,343	*
George Lindahl III [7]	64,343	*
Gary R. Petersen [8]	928,484	1.9%
All directors and executive officers as a group (10 persons)	4,182,611	8.6%

* 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) All information in this table is based solely on a Schedule 13G filed on February 13, 2014 by the following persons ("Filing Parties"): Robert J. Raymond, RR Advisors, LLC, RCH Energy MLP Fund GP, L.P., RCH Energy MLP Fund, L.P., RCH Energy MLP Fund–A, L.P., RCH Energy Opportunity Fund II GP, L.P., RCH Energy Opportunity Fund II, L.P., and RCH Energy Long Alpha Fund, L.P. The Filing Parties report beneficial ownership over all or a portion of 3,675,386 common units. In addition, Robert J. Raymond reported the sole power to vote or to direct the voting of and the sole dispositive power over 45,000 of our common units set forth in the tale above. Each reporting person expressly disclaims (a) the existence of any group and (b) beneficial ownership with respect to any common units other than the common units owned of record by such reporting person.

(3) All information in the table with respect to Piper Jaffray Companies (“Piper Jaffray”) is based solely on the Schedule 13G/A filed by Piper Jaffray with the SEC on February 14, 2014. According to the Schedule 13G/A, Advisory Research, Inc. (“ARI”), a wholly-owned subsidiary of FMR and an investment advisor registered under Section 203 of the Investment Advisers Act of 1940, is the beneficial owner of 3,485,195 common units, or approximately 7.2% of our outstanding common units, as a result of acting as investment advisor to various clients. Piper Jaffray may be deemed to be the beneficial owner of the common units through control of ARI. However, Piper Jaffray disclaims beneficial ownership of such units.

(4) All information in the table with respect to FMR LLC (“FMR”) is based solely on the Schedule 13G/A filed by FMR with the SEC on February 14, 2014. According to the Schedule 13G/A, Fidelity Management & Research Company (“Fidelity”), a wholly-owned subsidiary of FMR and an investment adviser registered under Section 203 of the Investment Advisers Act of 1940, is the beneficial owner of 3,059,788 common units, or approximately 6.3% of our outstanding common units, as a result of acting as investment advisor to various investment companies registered under Section 8 of the Investment Company Act of 1940. Edward C. Johnson 3d and FMR, through its control of Fidelity and the Funds, each has sole power to dispose of the 3,059,788 shares owned by the Funds. The Schedule 13G states that members of the family of Edward C. Johnson 3d, Chairman of FMR, representing 49% of the voting power of FMR may be deemed under the Investment Company Act of 1940 to form a controlling group with respect to FMR. According to the Schedule 13G/A, the Funds’ Boards of Trustees has the sole power to vote or direct the voting of the shares owned directly by the Fidelity Funds. Fidelity carries out the voting of the shares under written guidelines established by the Funds’ Boards of Trustees. In addition, Pyramis Global Advisors Trust Company ("PGATC"), 900 Salem Street, Smithfield, Rhode Island, 02917, an indirect wholly–owned subsidiary of FMR and a bank as defined in Section 3(a)(6) of the Exchange Act, is the beneficial owner of 199,661 of our common units as a result of its serving as investment manager of institutional accounts owning such units. Edward C. Johnson 3d and FMR, through its control of PGATC, each has sole dispositive power over 199,661 common units and sole power to vote or to direct the voting of 199,661 common units owned by the institutional accounts managed by PGATC.

(5) Includes 1,733,098 common units owned by John B. and Lisa A. Walker, L.P., 10,400 common units owned by Mr. Walker’s spouse and 700 common units owned by Mr. Walker’s children. Mr. Walker disclaims beneficial ownership of these common units. Also includes 155,600 common units owned by EnerVest. Mr. Walker, by virtue of his direct and indirect ownership of the limited liability company that acts as EnerVest’s general partner, may be deemed to beneficially own the common units owned by EnerVest.

(6) Includes 320,488 common units owned by DSEA II, LP, a limited partnership of which Mr. Houser and his spouse manage the general partner and 190,800 common units owned by trusts for Mr. Houser’s children. Mr. Houser disclaims beneficial ownership of these common units.

(7) Includes 20,000 common units owned by a trust for Mr. Lindahl’s daughters and 300 common units owned by Mr. Lindahl’s spouse. Mr. Lindahl disclaims beneficial ownership of these common units.

(8) Includes 518,385 common units owned by EnCap Energy Capital Fund V, L.P. and 410,099 common units owned by EnCap V–B Acquisitions, L.P. EnCap V–B Acquisitions GP, LLC, as the general partner of EnCap V–B Acquisitions, L.P., EnCap Energy Capital Fund V–B, L.P., as the general partner of EnCap V–B Acquisitions GP, LLC, 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., may be deemed to share voting and dispositive control over the common units owned by EnCap Energy Capital Fund V, L.P. and EnCap V–B Acquisitions, L.P. Each of EnCap V–B Acquisitions GP, LLC, EnCap Energy Capital Fund V-B, L.P., EnCap Equity Fund V GP, L.P., EnCap Investments L.P., EnCap Investments GP, L.L.C., RNBD GP LLC, disclaim beneficial ownership of the securities in excess of such entity’s respective pecuniary interest in the securities. Gary R. Petersen is a member of RNBD GP LLC, and disclaims beneficial ownership of the securities owned by EnCap Energy Capital Fund V, L.P. and EnCap V-B Acquisitions, L.P.

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

The number of common units which we may issue under the Plan is 4.5 million. The following table summarizes information about our equity compensation plans as of December 31, 2013:

	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	1,147,756	–	2,226,566
Equity compensation plans not approved by security holders	–	–	–
Total	1,147,756	–	2,266,566

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

Our partnership agreement provides that whenever a potential conflict exists or arises between our general partner or its affiliates, on the one hand, and us, on the other hand, any resolution or course of action by the general partner shall be permitted and deemed approved by all of the partners, and shall not constitute a breach of the partnership agreement or any duty stated or implied by law or equity if the resolution or the course of action taken in respect of such conflict of interest is approved by a vote of a majority of the members of our conflicts committee. Our partnership agreement does not require that we submit potential conflicts to our conflicts committee, but as a matter of course, our general partner submits to our conflicts committee for review any transaction that involves or may involve a conflict of interest. Other than the provision of our partnership agreement, we have no written policies or procedures for the conflicts committee to follow in making these determinations.

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 all of 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 membership 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 preclosing 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 2013, we paid EnerVest $10.0 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 includes a deduction for the value of the awards we issue to EnerVest employees (including Messrs. Walker and Houser) who perform services for us. 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, 2013. In February 2014, EV Management and EnerVest extended the term of the omnibus agreement through December 2014.

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 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 2013, we reimbursed EnerVest approximately $17.1 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

EnerVest is the general partner of institutional partnerships formed to acquire, develop and produce oil and natural gas properties. EnerVest generally has a 1% to 1.5% interest in the institutional partnerships that they manage, which increases to 20% following return of invested capital and a stated rate of return.

In November 2013, we, along with certain institutional partnerships managed by EnerVest, acquired natural gas properties in the Barnett Shale. We acquired a 31% proportional interest in these properties for an aggregate purchase price of $66.0 million, subject to customary purchase price adjustments.

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.

Overriding Royalty Interest Partnership

In 2011, we and certain institutional partnerships managed by EnerVest carved out a 7.5% ORRI from certain acres in Ohio (the "Underlying Properties"), which we believe may be prospective for the Utica Shale, and contributed the ORRI to a newly formed limited partnership. EnerVest is the general partner of this partnership. The ORRI entitles the partnership to an average approximate 5.64% of the gross revenues from the Underlying Properties. We own a 48% limited partner interest in the partnership. In 2013, we recognized $0.2 million of income from unconsolidated affiliates, and we received $0.2 million of distributions.

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 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 2013, we awarded an aggregate of 0.2 million phantom units to such employees. The market value of these units on the date of grant was approximately $8.0 million.

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, 2013. 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, 2013 were approved by the audit committee.

Fees approved to be paid to Deloitte & Touche LLP are as follows:

	2013	2012
Audit fees [1]	$ 1,025,000	$ 951,300
Audit–related fees	80,500[2]	74,286[3]
Tax fees	–	–
All other fees	–	–
Total	$ 1,105,500	$ 1,025,586

(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 our public equity offering in October 2013.

(3) Represents fees for professional services provided in connection with our Form S–3 filing in March 2012.

PART IV

ITEM 15. EXHIBITS AND 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).
4.1	Indenture, dated as of March 22, 2011, by and among EV Energy Partners, L.P., EV Energy Finance Corp., the Guarantors named therein and U.S. National Bank Association, as trustee (incorporated by reference from Exhibit 4.1 to EV Energy Partners L.P.'s current report on Form 8–K filed with the SEC on March 22, 2011).
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).
10.2	Contract Operating Agreement, dated September 29, 2006, by and among EnerVest Operating, L.L.C. and EnerVest Production Partners, 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 October 5, 2006).
10.3	Contract Operating Agreement, dated September 29, 2006, by and among EnerVest Operating, L.L.C. and CGAS Properties, L.P. (incorporated by reference from Exhibit 10.3 to EV Energy Partners, L.P.'s current report on Form 8–K filed with the SEC on October 5, 2006).
*10.4	EV Energy Partners, L.P. Long–Term Incentive Plan (incorporated by reference from Exhibit 10.4 to EV Energy Partners, L.P.'s current report on Form 8–K filed with the SEC on October 5, 2006).

*10.5	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).
+10.6	Omnibus Agreement Extension, dated February 25, 2014, by and between EnerVest, Ltd. and EV Energy GP, L.P.
*10.7	Form of EV Energy Partners, L.P. Incentive Unit Agreements (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 March 18, 2009).
10.8	Underwriting Agreement dated as of March 4, 2011, 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, LLC, Citigroup Global Markets Inc., Credit Suisse Securities (USA) LLC, J.P. Morgan Securities LLC, 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 March 10, 2011).
10.9	Second Amended and Restated Credit Agreement, dated as of April 26, 2011 by and among EV Energy Partners, L.P., EV Properties, L.P., and JPMorgan Chase Bank, N.A. as Administrative Agent for the lenders named therein (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 April 29, 2011).
10.10	First Amendment dated December 21, 2011 to Second 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 December 27, 2011).
10.11	Second Amendment dated March 29, 2012 to Second 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 April 4, 2012).
10.12	Third Amendment dated September 27, 2012 to Second 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 October 3, 2012).
10.13	Amended and Restated Assignment Agreement dated October 1, 2012 between M3 Ohio Gathering LLC, Utica Gas Services, L.L.C., CGAS Properties, L.P. and Utica East Ohio Midstream L.L.C. (incorporated by reference from Exhibit 10.17 to EV Energy Partners L.P.'s annual report on Form 10–K filed with the SEC on March 1, 2013).
10.14	Fourth Agreement dated as of February 26, 2013 to Second Amended and Restated Credit Agreement (incorporated by reference from Exhibit 10.18 to EV Energy Partners L.P.'s annual report on Form 10–K filed with the SEC on March 1, 2013).
10.15	Fifth Agreement dated as of August 7, 2013 to Second Amended and Restated Credit Agreement (incorporated by reference from Exhibit 10.1 to EV Energy Partners, L.P.'s quarterly report on Form 10–K filed with the SEC on August 9, 2013).
10.16	Underwriting Agreement dated as of October 18, 2013, among EV Energy Partners, L.P., EV Energy GP, L.P., EV Management, LLC, EV Properties, L.P., EV Properties GP, LLC, Wells Fargo Securities, LLC, Citigroup Global Markets Inc., J.P. Morgan Securities LLC, Raymond James & Associates, Inc., RBC Capital Markets, LLC, Robert W. Baird & Co. Incorporated and Credit Suisse Securities (USA) 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 October 23, 2013).
+21.1	Subsidiaries of EV Energy Partners, L.P.
+23.1	Consent of Cawley, Gillespie & Associates, Inc.

+23.2	Consent of Deloitte & Touche LLP.
+31.1	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer.
+31.2	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer.
+32.1	Section 1350 Certification of Chief Executive Officer
+32.2	Section 1350 Certification of Chief Financial Officer
+99.1	Cawley, Gillespie and Associates, Inc. Reserve Report.
+101	Interactive Data Files

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* 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, 2014

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	Executive Chairman and Director (principal executive officer)	February 28, 2014
/s/MARK A. HOUSER Mark A. Houser	President, Chief Executive Officer and Director	February 28, 2014
/s/MICHAEL E. MERCER Michael E. Mercer	Senior Vice President and Chief Financial Officer (principal financial officer)	February 28, 2014
/s/RYAN J. FLORY Ryan J. Flory	Controller (principal accounting officer)	February 28, 2014
/s/VICTOR BURK Victor Burk	Director	February 28, 2014
/s/JAMES R. LARSON James R. Larson	Director	February 28, 2014
/s/GEORGE LINDAHL III George Lindahl, III	Director	February 28, 2014
/s/GARY R. PETERSEN Gary R. Petersen	Director	February 28, 2014

EXHIBIT INDEX

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).

4.1 Indenture, dated as of March 22, 2011, by and among EV Energy Partners, L.P., EV Energy Finance Corp., the Guarantors named therein and U.S. National Bank Association, as trustee (incorporated by reference from Exhibit 4.1 to EV Energy Partners L.P.'s current report on Form 8–K filed with the SEC on March 22, 2011).

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).

10.2 Contract Operating Agreement, dated September 29, 2006, by and among EnerVest Operating, L.L.C. and EnerVest Production Partners, 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 October 5, 2006).

10.3 Contract Operating Agreement, dated September 29, 2006, by and among EnerVest Operating, L.L.C. and CGAS Properties, L.P. (incorporated by reference from Exhibit 10.3 to EV Energy Partners, L.P.'s current report on Form 8–K filed with the SEC on October 5, 2006).

*10.4 EV Energy Partners, L.P. Long–Term Incentive Plan (incorporated by reference from Exhibit 10.4 to EV Energy Partners, L.P.'s current report on Form 8–K filed with the SEC on October 5, 2006).

*10.5 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).

+10.6 Omnibus Agreement Extension, dated February 25, 2014, by and between EnerVest, Ltd. and EV Energy GP, L.P.

*10.7 Form of EV Energy Partners, L.P. Incentive Unit Agreements (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 March 18, 2009).

10.8 Underwriting Agreement dated as of March 4, 2011, 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, LLC, Citigroup Global Markets Inc., Credit Suisse Securities (USA) LLC, J.P. Morgan Securities LLC, 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 March 10, 2011).

10.9 Second Amended and Restated Credit Agreement, dated as of April 26, 2011 by and among EV Energy Partners, L.P., EV Properties, L.P., and JPMorgan Chase Bank, N.A. as Administrative Agent for the lenders named therein (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 April 29, 2011).

10.10 First Amendment dated December 21, 2011 to Second 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 December 27, 2011).

10.11 Second Amendment dated March 29, 2012 to Second 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 April 4, 2012).

10.12 Third Amendment dated September 27, 2012 to Second 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 October 3, 2012).

10.13 Amended and Restated Assignment Agreement dated October 1, 2012 between M3 Ohio Gathering LLC, Utica Gas Services, L.L.C., CGAS Properties, L.P. and Utica East Ohio Midstream L.L.C. (incorporated by reference from Exhibit 10.17 to EV Energy Partners L.P.'s annual report on Form 10–K filed with the SEC on March 1, 2013).

10.14 Fourth Agreement dated as of February 26, 2013 to Second Amended and Restated Credit Agreement (incorporated by reference from Exhibit 10.18 to EV Energy Partners L.P.'s annual report on Form 10–K filed with the SEC on March 1, 2013).

10.15 Fifth Agreement dated as of August 7, 2013 to Second Amended and Restated Credit Agreement (incorporated by reference from Exhibit 10.1 to EV Energy Partners, L.P.'s quarterly report on Form 10–K filed with the SEC on August 9, 2013).

10.26 Underwriting Agreement dated as of October 18, 2013, among EV Energy Partners, L.P., EV Energy GP, L.P., EV Management, LLC, EV Properties, L.P., EV Properties GP, LLC, Wells Fargo Securities, LLC, Citigroup Global Markets Inc., J.P. Morgan Securities LLC, Raymond James & Associates, Inc., RBC Capital Markets, LLC, Robert W. Baird & Co. Incorporated and Credit Suisse Securities (USA) 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 October 23, 2013).

+21.1 Subsidiaries of EV Energy Partners, L.P.

+23.1 Consent of Cawley, Gillespie & Associates, Inc.

+23.2 Consent of Deloitte & Touche LLP.

+31.1 Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer.

+31.2 Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer.

+32.1 Section 1350 Certification of Chief Executive Officer

+32.2 Section 1350 Certification of Chief Financial Officer

+99.1 Cawley, Gillespie and Associates, Inc. Reserve Report.

+101 Interactive Data Files

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* Management contract or compensatory plan or arrangement

\+ Filed herewith

Exhibit 10.6

OMNIBUS AGREEMENT EXTENSION

This Omnibus Agreement Extension (“Agreement”) is entered into on February 25, 2014, and is by and between EnerVest, Ltd., (f/k/a EnerVest Management Partners, Ltd.) a Texas limited partnership (“EnerVest”) and EV Energy GP, LP, a Delaware limited partnership (the “General Partner”).

WHEREAS, the Omnibus Agreement (the “First Omnibus Agreement”), was entered into on September 29, 2006, by and among EnerVest, EV Management LLC, a Delaware limited liability company (“EV Management”), the General Partner, EV Energy Partners, LP, a Delaware limited partnership (the “Partnership”), and EV Properties, L.P., a Delaware limited partnership (“OLP”). Any capitalized term not defined herein shall have the meaning set forth therein;

WHEREAS, pursuant to Section 3.3 of the First Omnibus Agreement, EnerVest and the General Partner determine the amount of general and administrative expenses that will be properly allocated to the Partnership after December 31, 2008;

WHEREAS, the First Omnibus Agreement automatically renews each year if it is not terminated by either EnerVest or the General Partner;

WHEREAS, the First Omnibus Agreement was extended by the Omnibus Agreement Extensions entered into on December 17, 2008, December 10, 2009, December 21, 2010, December 20, 2011 and February 25, 2013;

WHEREAS, neither party has terminated the First Omnibus Agreement.

In consideration of the premises and the covenants, conditions, and agreements contained herein, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, EnerVest and the General Partner hereby agree as follows:

1. The First Omnibus Agreement shall continue in effect until December 31, 2014, subject to termination or automatic renewal on such date as provided in the First Omnibus Agreement.

2. The Partnership shall pay EnerVest a fee of $1,008,333.33 per month, $12.1 million annually, for the services described in the First Omnibus Agreement, subject to adjustment as provided in Section 3.3 therein.

IN WITNESS WHEREOF, the undersigned have executed this Agreement on, and effective as of, the date first set forth above.

ENERVEST, LTD.

By: EnerVest Management GP, L.C.,
its general partner

By: /s/ Mark A. Houser
Mark A. Houser
President and Chief Executive Officer

EV ENERGY GP, L.P.

By: EV Management, L.L.C.,
a Delaware limited liability company
its General Partner

By: /s/ Michael E. Mercer
Michael E. Mercer
Senior Vice President and Chief Financial Officer

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 Monroe Gathering, Ltd.	Texas
8.	EnerVest Monroe Marketing, Ltd.	Texas
9.	EV Midstream, LLC	Delaware
10.	EV Midstream, L.P.	Delaware

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, 2014

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, 2013 and the Registration Statement Nos. 333–179981 and 333–172593 on Form S–3 and Registration Statement Nos. 333–172624, 333– 163686 and 333–140205 on Form S–8 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.
Senior Vice President
Cawley, Gillespie & Associates, Inc.
Texas Registered Engineering Firm F-693

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333–179981 and 333–172593 on Form S–3 and Registration Statement Nos. 333–172624, 333– 163686 and 333–140205 on Form S–8 of EV Energy Partners, L.P. of our report dated February 28, 2014, relating to the consolidated financial statements of EV Energy Partners, L.P. and subsidiaries 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, 2013.

/s/DELOITTE & TOUCHE LLP
Houston, Texas
February 28, 2014

Exhibit 31.1

CERTIFICATIONS

I, Mark A. Houser, 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, 2014

/s/ MARK A. HOUSER
Mark A. Houser
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, 2014

/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, 2013 of EV Energy, L.P. (the “Partnership”) and filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Mark A. Houser, 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, 2014

/s/ MARK A. HOUSER
Mark A. Houser
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, 2013 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, 2014

/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

13640 BRIARWICK DRIVE, SUITE 100
AUSTIN, TEXAS 78729-1107
512-249-7000

306 WEST SEVENTH STREET, SUITE 302
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817- 336-2461
www.cgaus.com

1000 LOUISIANA STREET, SUITE 625
HOUSTON, TEXAS 77002-5008
713-651-9944

February 11, 2014

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, 2013

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 February 11, 2014 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, 2013, 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 composite summary form below:

		Proved Developed Producing	Proved Developed Non-Producing	Proved Developed	Proved Undeveloped	Total Proved
Net Reserves						
Oil	- Mbbl	10,024.4	419.1	10,443.4	2,640.7	13,084.1
Gas	- MMcf	536,709.6	41,563.6	578,273.5	241,406.4	819,679.8
NGL	- Mbbl	25,370.5	3,685.2	29,055.7	19,845.9	48,901.6
Revenue						
Oil	- M$	951,313.9	40,131.1	991,445.0	247,271.1	1,238,716.1
Gas	- M$	1,590,872.6	109,343.1	1,700,215.3	630,223.5	2,330,438.3
NGL	- M$	760,370.2	110,544.5	870,914.6	558,721.6	1,429,636.3
Net Profits	- M$	108.4	0.0	108.4	0.0	108.4
Severance Taxes	- M$	180,026.4	16,412.2	196,438.6	76,418.1	272,856.8
Ad Valorem Taxes	- M$	88,026.4	7,226.5	95,252.8	44,766.6	140,019.4
Operating Expenses	- M$	980,646.5	22,788.0	1,003,439.4	214,354.1	1,217,793.0
Other Deductions	- M$	264,501.4	17,591.6	282,089.4	84,958.5	367,048.6
Investments	- M$	70,956.4	47,665.1	118,621.5	393,097.0	511,718.7
Net Cash Flows	- M$	1,718,290.9	148,335.3	1,866,626.5	622,622.1	2,489,249.3
Discounted @ 10% ***(Present Worth)***	**- M$**	**856,527.0**	**47,723.6**	**904,250.6**	**145,155.9**	**1,049,406.4**

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.

Hydrocarbon Pricing

The base oil and gas prices calculated for December 31, 2013 were $96.78 per barrel and $3.666 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 2013 and the base gas price is based upon Henry Hub spot prices (Platt’s Gas Daily) during 2013.

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 $94.673 per barrel for oil, $2.843 per MCF for gas and $29.235 per barrel for natural gas liquids. All economic factors were held constant in accordance with SEC guidelines, except for certain properties with contractual agreements as specified by EVEP.

Economic Parameters

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 and completeness. 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, except for certain properties with contractual agreements as specified by EVEP.

SEC Conformance and Regulations

The reserve classifications and the economic considerations used herein conform to the guidelines as established by the SEC. 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 706 proved undeveloped locations, with the bulk of the projected value from 533 locations in the Barnett Shale region (Texas) and 97 locations in the Range Appalachia region (OH, PA & MI). 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

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 been included on commercial producing wells at the end of the economic life of the producing cases in the SEC pricing evaluation. The cost of plugging and salvage value of equipment at abandonment have not been included elsewhere herein.

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, Senior 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.
Senior Vice President