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, 2006

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) 659-3500**

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 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, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. Check one:

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒

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 March 15, 2007 based on the closing price on the NASDAQ Global Market on March 15, 2007 was $261,294,920.

As of March 15, 2007, the registrant had 8,430,743 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.

Bcf. One billion cubic feet.

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).

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

Developed acres. Acres spaced or assigned to productive wells.

Dry hole or well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed production expenses and taxes.

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.

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

MMBbls. One million barrels.

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

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. Oil, condensate and natural gas liquids.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceeds production expenses and taxes.

Proved reserves. Proved oil and natural gas reserves, as defined by the Securities and Exchange Commission (the "SEC") in Article 4-10(a)(2) of Regulation S-X, are the estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, *i.e.*, prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based on future conditions. Comprehensive SEC oil and natural gas reserve definitions can be found on the SEC's website at *www.sec.gov/about.forms/regs-x.pdf*.

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and natural gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included in "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved undeveloped drilling location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

Proved undeveloped reserves or PUDs. 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. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

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

Reservoir. A porous and permeable underground formation containing a natural accumulation of produceable 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 (using prices and costs in effect as of the date of estimation) without giving effect to non-property related expenses such as certain general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization and discounted using an annual discount rate of 10%. Our standardized measure does not include future income tax expenses because we are not subject to income taxes.

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

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

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

References in this Annual Report on Form 10-K to "EV Energy Partners, L.P.," "we," "our" or "us" or like terms when used in a historical context prior to October 1, 2006 refer to the combined operations of CGAS Exploration, Inc. and EV Properties, L.P. (collectively, the "Combined Predecessor Entities"). When used in a historical context on or after October 1, 2006, the present tense or prospectively, those terms refer to EV Energy Partners, L.P. and its subsidiaries. Reference to "EnerVest" refers to EnerVest Management Partners, Ltd. and its partnerships and other entities under common ownership.

Overview

We are a Delaware limited partnership formed in April 2006 by EnerVest to acquire, produce and develop oil and natural gas properties. We consummated the acquisition of our predecessors and an initial public offering of our common units effective October 1, 2006. 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.

Our predecessors were:

- EV Properties, L.P. ("EV Properties"), a limited partnership that owned oil and natural gas properties and related assets in the Monroe Field in Northern Louisiana and in the Appalachian Basin in West Virginia, and
- CGAS Exploration, Inc. ("CGAS Exploration"), a corporation that owned oil and natural gas properties and related assets in the Appalachian Basin primarily in Ohio.

EV Properties was formed in the second quarter of 2006 by EnerVest, as general partner, and EnerVest, EV Investors, L.P. ("EV Investors") and investment funds formed by EnCap Investments, L.P. ("EnCap"), as limited partners, to acquire the business of the following partnerships which were controlled by EnerVest:

- EnerVest Production Partners, Ltd. ("EnerVest Production Partners"), a limited partnership that owned oil and natural gas properties and related assets in the Monroe Field in Northern Louisiana, and
- EnerVest WV, L.P. ("EnerVest WV"), a limited partnership that owned oil and natural gas properties and related assets in West Virginia.

Effective October 1, 2006, we completed our initial public offering of 3.9 million common units at a price of $20.00 per unit, and on October 26, 2006, we closed the sale of an additional 0.4 million common units at a price per unit of $20.00 pursuant to the exercise of the underwriters' over-allotment option. Net proceeds after underwriting discounts, structuring fees and offering costs from the sale of the common units were approximately $76.6 million.

On December 15, 2006, we acquired oil and natural gas properties in Louisiana, Texas and Oklahoma from Five States Energy Company, LLC (the "Five States Acquisition") for $27.6 million. Estimated net proved reserves attributable to these properties at December 31, 2006 were 14.8 Bcfe, of which 8.9 Bcfe were natural gas. The acquisition was funded with borrowings under our credit facility.

In January 2007, we acquired natural gas properties in Michigan from an institutional partnership managed by EnerVest for $71.4 million. Estimated net proved reserves attributable to these properties at December 31, 2006 were 56.3 Bcfe, all of which were natural gas. The acquisition was funded with borrowings under our credit facility.

In March 2007, we acquired additional natural gas properties in the Monroe Field in Louisiana from an institutional partnership managed by EnerVest for $95.3 million. Estimated net proved reserves attributable to these properties at December 31, 2006 were 65.2 Bcfe, all of which were natural gas. The acquisition was funded with borrowings under our credit facility.

Information regarding reserves, present values, drilling results, acreage, well counts and other operating and financial information in this annual report on Form 10-K does not include information attributable to the Michigan or Monroe Field acquisitions.

In February 2007, we issued 3.9 million common units to institutional investors in a private placement for $100.0 million, including a $2.0 million contribution by our general partner to maintain its 2% interest in us. We used the proceeds of this issuance to repay all of the indebtedness under our credit facility. The borrowings repaid with the proceeds of the offering represented the borrowings made to finance our Five States and Michigan acquisitions. Our financial information included in this annual report on Form 10-K does not include this offering, unless otherwise indicated.

We operate in one reportable segment engaged in the exploration, development and production of oil and natural gas properties. At December 31, 2006, our properties were located in the Appalachian Basin (primarily in Ohio and West Virginia), the Monroe Field in Northern Louisiana and the Mid-Continent areas in Oklahoma, Texas and Louisiana, and had estimated net proved reserves of 2.0 MMBbls of oil and 49.4 Bcf of natural gas, or 61.5 Bcfe, and a present value of future net cash flows, discounted at 10%, or standardized measure, of $105.0 million.

Oil and natural gas reserve information is derived from our reserve report prepared by Cawley, Gillespie & Associates, Inc., our independent reserve engineers. The following table summarizes information about our oil and natural gas reserves by geographic region as of December 31, 2006:

	Estimated Net Proved Reserves(1)			
	Developed	Undeveloped	Total	Standardized Measure(2)
		(Bcfe)		($ in millions)
Appalachian Basin	28.4	4.0	32.4	$ 62.1
Monroe Field	14.3	—	14.3	15.1
Mid-Continent area	14.8	—	14.8	27.8
Total	57.5	4.0	61.5	$ 105.0

(1) Does not include 56.3 Bcfe of estimated net proved reserves attributable to the Michigan properties acquired in January 2007 or 65.2 Bcfe of estimated net proved reserves attributable to the acquisition of additional Louisiana properties in the Monroe Field acquired in March 2007.

(2) Standardized measure is calculated in accordance with Statement of Financial Accounting Standards ("SFAS") No. 69, *Disclosures About Oil and Gas Producing Activities.* Because we are a limited partnership, we have made no provision for federal or state income taxes in the calculation of standardized measure.

Business Strategy

Our primary business objective is to provide stability and growth in our cash distributions per unit over time. We intend to accomplish this objective by executing the following business strategies:

- replace and increase our reserves and production over the long term by pursuing acquisitions of long-lived producing oil or natural gas properties with low decline rates, predictable production profiles and relatively low risk drilling opportunities;
- maintain an inventory of proved undeveloped drilling locations, which are sufficient when drilled and completed to allow us to maintain our production levels over the near-term;
- maintain low levels of indebtedness to permit us to finance opportunistic acquisitions;
- reduce exposure to commodity price risk through hedging;
- retain control over the operation of a substantial portion of our production; and
- focus on controlling the costs of our operations.

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:

- *Drilling inventory*. We have a substantial inventory of low risk, proved undeveloped drilling locations.
- *Long life reserves with predictable decline rates*. Our properties generally have a long reserve to production index, with predictable decline rates.

- *Experienced management team*. Our management is experienced in oil and natural gas acquisitions and operations. Our executive officers average over 25 years of industry experience, and over eight years of experience acquiring and managing oil and natural gas properties for EnerVest partnerships.
- *Relationship with EnerVest*. Our relationship with EnerVest provides us with a wide breadth of operational, technical, risk management and other expertise across a wide geographical range, which will assist us in evaluating acquisition and development opportunities. EnerVest's primary business is to acquire and manage oil and natural gas properties for partnerships formed with institutional investors. These partnerships focus on maximizing investment returns for investees, including the sale of oil and natural gas properties.

Acquisitions of Our Properties

We acquired the properties that we owned as of December 31, 2006 in the following transactions:

- our predecessors acquired certain Monroe Field properties in 2000 and 2005 and our Appalachian properties in Ohio and West Virginia in 2003;
- we acquired these properties from our predecessors in October 2006; and
- we acquired oil and natural gas properties in the Five States acquisition in December 2006.

In addition, we acquired natural gas properties in Michigan from institutional partnerships managed by EnerVest in January 2007 and, in March 2007, we acquired additional properties in the Monroe Field in Louisiana from an institutional partnership managed by EnerVest.

Our Relationship with EnerVest

One of our principal attributes is our relationship with EnerVest. Through our omnibus agreement, EnerVest agreed to make available to us sufficient of its personnel to permit us to carry on our business in the same manner in which it was carried on by our predecessors. 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 $1.5 billion. EnerVest acts as an operator of over 10,000 oil and natural gas wells in 11 states.

EnerVest has substantial experience acquiring, owning and operating properties in the Appalachian Basin, the Monroe Field and the Michigan area. EnerVest has acquired and operated properties in the Appalachian Basin since 1995, in the Monroe Field since 1998 and in Michigan since 2005 for its account and for the EnerVest partnerships.

EnerVest and its affiliates have a significant interest in our partnership through their 71.25% ownership of our general partner, which, in turn, owns a 2% general partner interest in us and all of our incentive distribution rights. Additionally, as of March 15, 2007, EnerVest, its employees and affiliates owned an aggregate of 1.9% of our outstanding common units and 85.9% of our outstanding subordinated units. At the closing of our initial public offering, we entered into the omnibus agreement with EnerVest that governs our relationship with them regarding certain reimbursement and indemnification matters.

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. In addition, 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. Properties targeted by the EnerVest partnerships for acquisition typically have a lower amount of proved producing reserves and higher risk exploitation and development opportunities than the properties that we will target. The agreement for one of the current EnerVest partnerships, however, provides that if EnerVest becomes aware, other than in its capacity as an owner of our general partner, of acquisition opportunities that are suitable for purchase by the EnerVest partnership, EnerVest must first offer those opportunities to that EnerVest partnership, in which case we would be offered the opportunities only if the EnerVest partnership chose not to pursue the acquisition. EnerVest's obligation to offer acquisition opportunities to its existing EnerVest partnership will not apply to acquisition opportunities which we generate internally, and EnerVest has agreed with us that for so long as it controls our general partner it will not enter into any agreements which would limit our ability to pursue acquisition opportunities that we generate internally.

Our Areas of Operation

As of December 31, 2006, our properties were located in various fields in the Appalachian Basin, the Monroe Field in Louisiana and the Mid-Continent area of Oklahoma, Texas and Louisiana. In January 2007, we acquired natural gas properties in Michigan from an institutional partnership managed by EnerVest and, in March 2007, we acquired additional properties in the Monroe Field from an institutional partnership managed by EnerVest.

Appalachian Basin

The Appalachian Basin includes fields in Kentucky, Maryland, New York, Ohio, Pennsylvania, Virginia, West Virginia and Tennessee, and covers an area of over 185,000 square miles. It is the most mature oil and natural gas producing region in the United States, first establishing oil production in 1859. The Appalachian Basin is located near major consuming markets of the Northeastern United States. As a result of the proximity to major consuming markets and the high Btu content of Appalachia natural gas, the natural gas from the area typically commands a higher well head price relative to natural gas produced in other North American areas.

Operations in the area typically result in long-lived reserves, high drilling success rates and a large number of shallow wells with predictable decline rates. There are more than 200,000 producing wells in the Appalachian Basin. The low porosity and permeability sand and shale formations permit most wells to be relatively shallow, ranging from 1,000 to 6,000 feet. In general, these wells have stable production profiles and long-lived production, often with total projected remaining economic lives in excess of 30 years. In the Appalachian Basin, average decline rates after several years of production typically range from 5% to 10% per year. Once drilled and completed, operating and maintenance requirements for producing wells in the Appalachian Basin are generally low and only minimal, if any, capital expenditures are required.

In addition, wells in the Appalachian Basin are typically drilled on relatively close spacing of between 10 to 40 acres per well due to the low permeability of the producing formations. Generally, the distance between wells is less than 2,000 feet and wells are located within 5,000 feet from gathering and sales lines. As a result, most of our wells are producing and connected to a pipeline within 14 days (some as quickly as two days) after drilling and stimulation have been completed.

Our activities are concentrated in the Ohio and West Virginia areas of the Appalachian Basin. We own an average 92% working interest in 797 gross producing wells. As of December 31, 2006, our estimated net proved reserves in the Appalachian Basin were 1,042.4 MBbls of oil and 26.2 Bcfe of natural gas, or 32.4 Bcfe. During 2006, we drilled 18 wells on the properties that we acquired, and we intend to drill 20 Appalachian wells in 2007, all of which we expect to operate.

Ohio Area. Our Ohio area properties are located in 22 counties in Eastern Ohio and three counties in Western Pennsylvania. We own an average 92% working interest in 652 gross producing wells. We produce both oil and natural gas in this area, predominately from the Clinton reservoir, a blanket sand found at depths ranging from 3,155 to 5,500 feet. Our estimated net proved reserves in the Ohio area as of December 31, 2006 were 956 MBbls of oil, or 5.7 Bcfe, and 18.5 Bcf of natural gas, or 24.3 Bcfe. These estimated reserves were 76% natural gas on an Mcfe basis. EnerVest operated wells representing approximately 98% of our estimated net proved developed reserves in this area.

West Virginia Area. Our West Virginia area properties are located in seven counties in North Central West Virginia and one county in Southwestern Pennsylvania. We own an average 92% working interest in 145 gross producing wells. We produce mostly natural gas (94% on an Mcfe basis) from up to nine different zones at depths of between 2,500 and 5,500 feet. We typically complete these wells in four of the nine zones to optimize production. Our estimated net proved reserves in the West Virginia area as of December 31, 2006 were 86.4 MBbls of oil and 7.6 Bcf of natural gas, or 8.2 Bcfe. EnerVest operated wells representing 99% of the estimated net proved reserves in this area.

Monroe Field

Our Monroe Field properties are located in three parishes in Northeast Louisiana. The Monroe Field is one of the oldest fields in the United States, first establishing production in 1916. In this field we produce natural gas from the Monroe gas rock formation at approximately 2,200 feet.

Our estimated net proved reserves as of December 31, 2006 in the Monroe Field, 100% of which is natural gas, was 14.3 Bcfe. EnerVest operated wells representing all of our production in this area.

During 2006, we drilled six wells, all of which were successfully completed as producers. Four gross (four net) wells were drilled to the shallower Sparta formation at a depth of approximately 450 feet and two gross (two net) wells were drilled to the Monroe gas rock formation. We are continuing our review of the area where we drilled the Monroe gas rock wells for additional potential drilling and estimate five to ten potential remaining drillable locations, none of which have been assigned proved undeveloped reserves in our 2006 reserve report.

Mid-Continent Area

We acquired our Mid-Continent area properties in December 2006. The properties are primarily located in six counties in Western Oklahoma, three counties in Texas and two parishes in North Louisiana. Our estimated net proved reserves as of December 31, 2006 were 14.8 Bcfe, 60% of which is natural gas. We do not operate any of the wells in this area.

Our Oil and Natural Gas Data

Our Reserves

The following table presents our estimated net proved oil and natural gas reserves and the present value of our estimated net proved reserves at December 31, 2006:

Reserve Data(1):	
Estimated net proved reserves:	
Oil (MMBbls)	2.0
Natural gas (Bcf)	49.4
Total (Bcfe)	61.5
Proved developed (Bcfe)	57.5
Proved undeveloped (Bcfe)	4.0
Proved developed reserves as a % of total proved reserves	93 %
Standardized measure (in millions)	$ 105.0

(1) Does not include reserves attributable to the Michigan properties acquired in January 2007 or the additional Louisiana properties in the Monroe Field acquired in March 2007.

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 on which a relatively major expenditure is required for recompletion. See “Glossary of Oil and Natural Gas Terms.”

The data in the above table represents estimates only. Oil and natural gas reserve engineering is inherently a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of natural gas and oil 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 cash flows to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (using prices and estimated costs in effect as of the date of estimation) without giving effect to non-property related expenses such as certain 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 or state income taxes in the calculation of standardized measure. 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 Productive Wells

The following table sets forth information relating to the productive wells in which we owned a working interest as of December 31, 2006. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have a working interest in, 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 all wells. We compute the number of net wells we own by totaling the percentage interests we hold in all our gross wells.

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

	Gross Wells(1)			Net Wells(1)		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
Appalachian Basin						
Operated	15	759	774	14	708	722
Non-operated(2)	—	23	23	—	9	9
Monroe Field:						
Operated	—	1,078	1,078	—	1,078	1,078
Non-operated	—	—	—	—	—	—
Mid-Continent area:						
Non-operated	296	86	382	17	14	31
Total	311	1,946	2,257	31	1,809	1,840

(1) Does not include wells attributable to the Michigan properties acquired in January 2007 or the additional Louisiana properties in the Monroe Field acquired in March 2007.

(2) In addition, we own small royalty interests in an additional 55 wells.

Our Developed and Undeveloped Acreage

The following table sets forth information relating to our leasehold acreage as of December 31, 2006:

	Developed Acreage(1)		Undeveloped Acreage(1)	
	Gross	Net	Gross	Net
Appalachian Basin:				
Operated	21,648	20,500	58,005	52,463
Non-operated	846	348	12,929	5,055
Monroe Field:				
Operated	1,078	1,078	97,629	77,151
Non-operated	—	—	—	—
Mid-Continent area:				
Non-operated	18,467	5,853	254	254
Total	42,039	27,779	168,817	134,923

(1) Does not include acreage attributable to the Michigan properties acquired in January 2007 or the additional Louisiana properties in the Monroe Field acquired in March 2007.

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 own the leases.

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 natural gas leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion or review previously obtained title opinions. As a result, we have obtained title opinions on a significant portion of our natural gas properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the natural gas and oil industry. Our properties are subject to customary royalty and other interests, liens for current taxes and other burdens that we believe do not materially interfere with the use of or affect our carrying value of the properties.

Our Drilling Activity

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

The following table summarizes our approximate gross and net interest in wells completed by us during the three months ended December 31, 2006 and by our predecessors during the nine months ended September 30, 2006 and the years ended December 31, 2005 and 2004, 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.

	Successor	Predecessor(1)		
	Three Months Ended December 31, 2006	Nine Months Ended September 30, 2006	Year Ended December 31, 2005	Year Ended December 31, 2004
Gross wells:				
Productive	7.0	30.0	27.0	10.0
Dry	—	4.0	7.0	6.0
Total	7.0	34.0	34.0	16.0
Net wells:				
Productive	7.0	20.6	15.4	10.2
Dry	—	1.0	3.2	3.4
Total	7.0	21.6	18.6	13.6

(1) CGAS Exploration, one of our predecessors, was engaged in exploratory drilling. We did not acquire the exploration business from CGAS Exploration, and we do not expect that our exploratory drilling operations will be material in the future.

As of December 31, 2006, we were participating in the drilling of zero gross (zero net) wells.

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 a well and manages the day to day operating and maintenance activities for our wells.

Under the 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 will be 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 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 will be 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.

Natural Gas Gathering

We own and operate a network of natural gas gathering systems in both our Appalachian and Northern Louisiana areas of operation which gathers and transports our natural gas and a small amount of third party natural gas to larger gathering systems intrastate, interstate and local distribution pipelines. We gather all of our current production in the Monroe Field and more than 90% of our current production in Appalachia. Our network of natural gas gathering systems permits us to transport production from our wells with fewer interruptions and also minimizes any delays associated with a gathering company extending its lines to our wells. Our ownership and control of these lines enables us to realize:

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

Our natural gas gathering systems are operated for us by EnerVest pursuant to the operating agreement.

West Virginia Processing Arrangements

Substantially all of our natural gas production in West Virginia is processed through the Hastings-Dominion natural gas processing plant in central West Virginia to remove natural gas liquids. The processing occurs after title to our natural gas is passed to the marketing companies that purchase natural gas from us, so we are not party to natural gas processing contracts. However, if the Hastings-Dominion natural gas plant were to cease operations for any reason, purchasers of our natural gas would be required to make alternative arrangements to transport and process our natural gas production. Although there are pipelines which could transport our natural gas production to alternative processing facilities, we would expect that such pipelines would charge an incremental fee which would be passed on to us under the terms of our agreements with our purchasers. In addition, the alternative pipelines in the area would not have sufficient capacity to transport all of the natural gas production from the area that currently is processed through the Hastings-Dominion plant. As a result, if the Hastings-Dominion plant were to cease operations, we would expect that our West Virginia production would be curtailed. Although the amount of such curtailment would depend on numerous factors beyond our control, we would expect that our West Virginia production would be curtailed by approximately one half if the Hastings-Dominion plant were to shut down for an extended period of time.

Natural gas processing plants are large, complex industrial facilities, and are subject to risks such as fires, explosions, industrial accidents, labor related disruptions, and weather related damages. During 2003, an explosion occurred at the Hastings-Dominion plant which caused the plant to be closed for approximately two months.

Oil and Natural Gas Leases

The typical oil and natural gas lease agreement provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any well(s) drilled on the lease premises. In the Appalachian Basin, this amount is typically 1/8th (12.5%) resulting in an 87.5% net revenue interest to us. In the Monroe Field, this amount is typically 12.5% or less, resulting in an 87.5% or greater net revenue interest to us. In certain instances, this royalty amount may increase to 1/6th (16.66%) when leases are taken from larger landowners or mineral owners such as coal and timber companies. In our Mid-Continent area, the amount is typically between 1/8th (12.5%) and 1/4th (25%), resulting in a net revenue interest to us of between 75% and 87.5%.

Because the acquisition of oil and natural gas leases is a very competitive process, and involves certain geological and business risks to identify productive areas, prospective leases are often held by other oil and natural gas operators. In order to gain the right to drill these leases, we may elect to farm-in leases and/or purchase leases from other oil and natural gas operators. Typically the assignor of such leases will reserve an overriding royalty interest, ranging from 1/32nd to 1/16th (3.125% to 6.25%), which further reduces the net revenue interest available to us to between 84.375% and 81.25%.

Sometimes these third party owners of oil and natural gas leases retain the option to participate in the drilling of wells on leases farmed out or assigned to us. The retained interest normally ranges between a 10% and 50% working interest. In this event, our working interest ownership will be reduced by the amount retained by the third party owner.

Substantially all of our oil and natural gas leases are held by production, which means that for as long as our wells continue to produce oil or natural gas, we will continue to own the lease.

Principal Customers and Marketing Arrangements

We sell our Appalachian natural gas production to marketing companies under contracts that generally have a one year term. These contracts require the marketing company to purchase all of our natural gas production that we produce from wells subject to the contracts at prices based on the NYMEX price for natural gas less a gathering and transportation fee on substantially all of our Ohio area natural gas production. Under the terms of these contracts, we are not required to deliver a fixed quantity of oil or natural gas to the marketing company. We sell our Appalachian oil production at spot market prices. In 2006, three customers accounted for the purchase of 32%, 17% and 14%, respectively, of the combined oil and natural gas revenues of us and our predecessors, respectively. If we were to lose either of these oil or natural gas purchasers, the loss could temporarily cease production and sale of our oil or natural gas production from the wells subject to contracts with that purchaser. We believe, however, that we would be able promptly to replace the purchaser.

A portion of our Monroe Field natural gas production, representing 9% of the combined oil and natural gas revenues of us and our predecessors for 2006, was sold for us by Gas Masters of America, Inc., a private natural gas production company owned by the persons from whom we purchased some of our Northern Louisiana properties. Gas Masters sells our production to industrial users under contracts Gas Masters has with those users. The sales price is based on the NYMEX price for natural gas. Our arrangement with Gas Masters is month to month, and may be terminated at any time by us or Gas Masters.

The remainder of our natural gas production in the Monroe Field, representing 6% of the combined oil and natural gas revenues of us and our predecessors for 2006, was sold to EnerVest Monroe Marketing, Ltd. (“EnerVest Monroe Marketing”), a subsidiary of one of the EnerVest partnerships. EnerVest is the general partner of the partnership that owns EnerVest Monroe Marketing and has a 1% interest in that partnership. In 2006, the purchase price was spot market price based on the average of two index prices for natural gas production in the area, less a gathering fee of either $0.10 per Mcf or $0.75 per Mcf depending upon whether compression and additional gathering services or facilities are provided. EnerVest Monroe Marketing resold the natural gas, typically at a price based on one of the two indices for natural gas production in the area used to calculate our purchase price. EnerVest Monroe Marketing therefore realized a profit or loss on resales of our natural gas production when there was a difference between the average of the two indices used to calculate our purchase price and the index at which EnerVest Monroe Marketing re-sells its production. Beginning January 1, 2007, the natural gas prices received will be based on 98% of the net price that EnerVest Monroe Marketing receives less a gathering fee of either $0.10 per Mcf or $0.90 per Mcf, depending upon whether compression and additional gathering services or facilities are provided. In March 2007, we acquired EnerVest Monroe Marketing when we acquired the additional Louisiana properties in the Monroe Field.

We do not act as operator in our Mid-Continent area. We either sell our oil and natural gas production to third parties or are paid for our net share of production by the operator. The price we are paid by the operator is based on the relevant index based on the location of the property and, for both oil and natural gas, the price we are paid is at a discount to NYMEX prices.

Competition

The oil and natural gas industry is highly competitive. We encounter strong competition from other independent operators and from major oil companies in acquiring properties, 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 has delayed development drilling and other exploitation activities and has caused significant price increases. We are unable to predict when, or if, such shortages may occur or how they would affect our development and exploitation program.

Competition is also strong for attractive oil and natural gas producing properties, undeveloped leases and drilling rights, and we cannot assure you 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 in certain areas of the Appalachian Basin. As a result, we generally perform the majority of our drilling in the Appalachian Basin 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 well drilling objectives and increase competition for equipment, supplies and personnel during the drilling season, which could lead to shortages and increase costs or delay our operations. Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as warm winters or hot summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations.

Environmental Matters and Regulation

Our operations are subject to stringent and complex federal, state and local laws and regulations governing 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;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling, production and transportation activities;
- limit or prohibit drilling activities on lands lying within wilderness, wetlands and other protected areas; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as site restoration, pit closure and plugging of abandoned wells.

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 an increased costs for environmental compliance, such as waste handling, permitting, or cleanup, for the oil and natural gas industry and could have a significant impact on our operating costs.

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

Waste Handling

The Resource Conservation and Recovery Act (the "RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the federal Environmental Protection Agency (the "EPA"), the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own more stringent requirements. We generate both hazardous and non-hazardous wastes as a routine part of our operations. Although a substantial amount of the wastes generated in our operations are regulated as non-hazardous solid wastes rather than hazardous wastes, there is no guarantee that the EPA or individual states will not adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, 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 (the "CERCLA") imposes joint and several liability without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current and past owner or operator of the site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. Many states have adopted comparable or more stringent state statutes.

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 off-site locations, where such substances have been taken for disposal. In addition, some of these properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons 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. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property or perform remedial activities to prevent future contamination.

Water Discharges

The Federal Water Pollution Control Act (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 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 federal Clean Water Act and analogous state laws and regulations.

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

Air Emissions

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

National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act (the "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.

OSHA and Other Laws and Regulation

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

The Kyoto Protocol to the United Nations Framework Convention on Climate Change became effective in February 2005. Under the Protocol, participating nations are required to implement programs to reduce emissions of certain gases, generally referred to as greenhouse gases that are suspected of contributing to global warming. The United States is not currently a participant in the Protocol, and Congress has not actively considered recent proposed legislation directed at reducing greenhouse gas emissions. However, there has been support in various regions of the country for legislation that requires reductions in greenhouse gas emissions, and some states have already adopted legislation addressing greenhouse gas emissions from various sources, primarily power plants. The oil and natural gas industry is a direct source of certain greenhouse gas emissions, namely carbon dioxide and methane, and future restrictions on such emissions could impact our future operations. Our operations are not adversely impacted by current state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business.

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 three months ended December 31, 2006, and our predecessors did not incur any material capital expenditures for remediation or pollution control activities for the nine months ended September 30, 2006 and the years ended December 31, 2005 and 2004. Additionally, we are not aware of any environmental issues or claims that will require material capital expenditures during 2007 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 and ability to pay distributions to our unitholders.

Other Regulation of the Oil and Natural Gas Industry

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

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

Drilling and Production

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

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

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

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 is 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. Federal and state regulations govern the price and terms for access to natural gas pipeline transportation. The Federal Energy Regulatory Commission’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, or NGA, as well as under Section 311 of the Natural Gas Policy Act, or NGPA.

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 role 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.

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

State Natural Gas Regulation

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

Other Regulation

In addition to the regulation of oil pipeline transportation rates, the petroleum 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 the unitholders.

Employees

EV Management, the general partner of our general partner, has two full time employees and two executive officers who will spend a significant amount of their time on our operations. At December 31, 2006, EnerVest, the sole member of EV Management, had approximately 360 full-time employees, including over 50 geologists, engineers and landmen 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 relationships with its employees to be good.

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 Securities and Exchange Commission (the “SEC”). These documents are also available at 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 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 and subordinated units at the current distribution rate under our cash distribution policy.

In order to make our cash distributions at our anticipated quarterly distribution rates, we will require available cash of approximately $20.4 million in 2007 based on the common units, including the common units issued in February 2007, and subordinated units outstanding. We may not have sufficient available cash from operating surplus each quarter to enable us to make cash distributions at this anticipated quarterly distribution rate under our cash distribution policy. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the amount of oil and natural gas we produce;
- the prices at which we sell our oil and natural gas production;
- our ability to acquire additional oil and natural gas properties at economically attractive prices;
- our ability to hedge commodity prices;
- the level of our capital expenditures;
- the level of our operating and administrative costs; and
- the level of our interest expense, which depends of 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 collectibility 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.

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

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

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

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

- the domestic and foreign supply of and demand for oil and natural gas;

- the price and quantity of foreign imports of oil and natural gas;
- the level of consumer product demand;
- weather conditions;
- 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 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.

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

Restrictions in our credit facility will limit our ability to make distributions to you and may limit our ability to capitalize on acquisitions and other business opportunities.

Our credit facility contains covenants limiting our ability to make distributions, incur indebtedness, grant liens, make acquisitions, investments or dispositions and engage in transactions with affiliates, as well as containing covenants requiring us to maintain certain financial ratios and tests.

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

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

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

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

The standardized measure of discounted future net cash flows of our estimated net proved reserves is not necessarily the same as the current market value of our estimated net proved reserves. We base the discounted future net cash flows from our estimated net proved reserves on prices and costs in effect on the day 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 natural gas and oil 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 development operations will require substantial capital expenditures, which will reduce our cash available for distribution. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our production and reserves.

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

- the estimated quantities of our oil and natural gas reserves;
- the amount of oil and natural gas we produce from existing wells;
- the prices at which we sell our production; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our credit facility decrease as a result of lower commodity prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. Our credit facility may restrict our ability to obtain new financing. If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or available under our credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our prospects, which in turn could lead to a possible decline in our reserves and production, which could lead to a decline in our oil and natural gas reserves, and could adversely effect our business, results of operation, financial conditions and ability to make distributions to you. In addition, we may lose opportunities to acquire oil and natural gas properties and businesses.

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

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

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

Higher oil and natural gas prices generally increase the demand for drilling rigs, equipment and crews and can lead to shortages of, and increasing costs for, drilling equipment, services and personnel. Shortages of, or increasing costs for, experienced drilling crews and oil field equipment and services could restrict our ability to drill the wells and conduct the operations which we currently have planned. Any delay in the drilling of new wells or significant increase in drilling costs could reduce our revenues and cash available for distribution.

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

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

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

- unexpected drilling conditions;
- facility or equipment failure or accidents;
- shortages or delays in the availability of drilling rigs and equipment;
- adverse weather conditions;
- compliance with environmental and governmental requirements;
- title problems;
- unusual or unexpected geological formations;
- pipeline ruptures;
- fires, blowouts, craterings and explosions; and
- uncontrollable flows of oil or natural gas or well fluids.

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

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

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

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

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

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

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

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

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

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

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources than us. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Many of our larger competitors not only drill for and produce oil and natural gas, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for natural gas properties and evaluate, bid for and purchase a greater number of properties than our financial or human resources permit. In addition, these companies may have a greater ability to continue drilling activities during periods of low oil and natural gas prices, to contract for drilling equipment, to secure trained personnel, and to absorb the burden of present and future federal, state, local and other laws and regulations. The oil and natural gas industry has periodically experienced shortages of drilling rigs, equipment, pipe and personnel, which has delayed development drilling and other exploitation activities and has caused significant price increases. Competition has been strong in hiring experienced personnel, particularly in the accounting and financial reporting, tax and land departments. In addition, competition is strong for attractive oil and natural gas producing properties, oil and natural gas companies, and undeveloped leases and drilling rights. We may be often outbid by competitors in our attempts to acquire properties or companies. Our inability to compete effectively with larger companies could have a material adverse impact on our business activities, financial condition and results of operations.

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

Our business activities are subject to operational risks, including:

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

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

As is customary in the industry, we maintain insurance against some but not all of these risks. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could therefore occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on our business activities, financial condition, results of operations and ability to pay distributions to our unitholders.

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

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

- the Clean Air Act and comparable state laws and regulations that impose obligations related to air emissions;
- the Clean Water Act and comparable state laws and regulations that impose obligations related to discharges of pollutants into regulated bodies of water;
- the RCRA, and comparable state laws that impose requirements for the handling and disposal of waste from our facilities; and
- 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.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental statutes, including the RCRA, CERCLA, the federal Oil Pollution Act and analogous state laws and 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. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other waste products into the environment.

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

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

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

Increases in interest rates, which have recently experienced record lows, could adversely impact our unit price and our ability to issue additional equity to make acquisitions and incur debt.

The credit markets recently have experienced 50 year record lows in interest rates. As the overall economy strengthens, it is possible that monetary policy will continue to tighten, resulting in higher interest rates to counter possible inflation. Interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. As with other yield oriented securities, our unit price is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank related yield oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue additional equity to make acquisitions, incur debt or for other purposes.

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

The marketability of our production will depend in part upon the availability and capacity of natural gas gathering systems, pipelines and other transportation facilities owned by third parties. Transportation space on the gathering systems and pipelines we utilize is occasionally limited or unavailable due to repairs or improvements to facilities or due to space being utilized by other companies that have priority transportation agreements. Our access to transportation options can also be affected by U.S. federal and state regulation of oil and natural gas production and transportation, general economic conditions and changes in supply and demand. Substantially all of our West Virginia production is processed through the Dominion Hastings plant. If this plant were to cease operations for any reason, including due to fire, explosions, severe weather conditions or terrorist attacks, we may be forced to cease production from our West Virginia properties. These factors and the availability of markets are beyond our control. If market factors dramatically change, the impact on our revenues could be substantial and could adversely affect our ability to produce and market oil and natural gas, the value of our units and our ability to pay distributions on our units.

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

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

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

Drilling operations in the Appalachian Basin 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 in Appalachia and the Monroe Field and our ability to service wells in these areas on a year around basis.

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 and EnCap, which will be limited partners of our general partner, will have conflicts of interest, which may permit them to favor their own interests to your detriment.

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

- we have acquired oil and natural gas properties from partnerships formed by EnerVest and partnerships in which EnerVest has an interest, and we may do so in the future;
- neither our partnership agreement nor any other agreement requires EnerVest or EnCap to pursue a business strategy that favors us or to refer any business opportunity to us;
- our general partner is allowed to take into account the interests of parties other than us, such as EnerVest and EnCap, in resolving conflicts of interest;
- our general partner determines the amount and timing of our drilling program and related capital expenditures, asset purchases and sales, borrowings, issuance of additional partnership securities and reserves, each of which can affect the amount of cash that is distributed to unitholders;
- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates; and
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

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

In order to maintain and increase our levels of production, we will need to acquire oil and natural gas properties. Several of the officers and directors of EV Management, the general partner of our general partner, who have responsibilities for managing our operations and activities hold similar positions with other entities that are in the business of identifying and acquiring oil and natural gas properties. For example, Mr. Walker is Chairman and Chief

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

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

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

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

Pursuant to the omnibus agreement we entered into with EnerVest, our general partner and others, EnerVest 1will 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 and subordinated 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 and subordinated 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 and subordinated units. This may result in lower distributions to holders of our common units in certain situations.

Our general partner has the right, at a time when there are no subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (25%) for each of the prior four consecutive fiscal quarters, to reset the initial cash target distribution levels at higher levels based on the distribution at the time of the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution amount will be reset to an amount equal to the average cash distribution amount per common unit for the two fiscal quarters immediately preceding the reset election (such amount is referred to as the “reset minimum quarterly distribution”) and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution amount.

In connection with resetting these target distribution levels, our general partner will be entitled to receive a number of Class B units. The Class B units will be entitled to the same cash distributions per unit as our common units and will be convertible into an equal number of common units. The number of Class B units to be issued will be equal to that number of common units whose aggregate quarterly cash distributions equaled the average of the distributions to our general partner on the incentive distribution rights in the prior two quarters. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion; however, it is possible that our general partner could exercise this reset election at a time when it is experiencing, or may be expected to experience, declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be issued our Class B units, which are entitled to receive cash distributions from us on the same priority as our common units, rather than retain the right to receive incentive distributions based on the initial target distribution levels. As a result, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued new Class B units to our general partner in connection with resetting the target distribution levels related to our general partner 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. Our general partner, its owners and their affiliates, and EnCap own 28.3% of our aggregate outstanding common and subordinated units. Also, if our general partner is removed without cause during the subordination period and units held by our general partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically convert into common units and any existing arrearages on our common units will be extinguished. A removal of our general partner under these circumstances would adversely affect our common units by prematurely eliminating their distribution and liquidation preference over our subordinated units, which would otherwise have continued until we had met certain distribution and performance tests. Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding the general partner liable for actual fraud or willful or wanton misconduct in its capacity as our general partner. Cause does not include most cases of charges of poor business management, so the removal of the general partner because of the unitholder's dissatisfaction with our general partner's performance in managing our partnership will most likely result in the termination of the subordination period and conversion of all subordinated units to common units.

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;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- 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.

EnerVest, EV Investors, CGAS Exploration and EnCap may sell common units in the public markets, which sales could have an adverse impact on the trading price of the common units.

EnerVest, EV Investors, CGAS Exploration and EnCap hold an aggregate of 3.1 million subordinated units. All of the subordinated units will convert into common units at the end of the subordination period and some may convert earlier. The sale of these units in the public markets could have an adverse impact on the price of the common units or on any trading market that may develop.

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 working capital borrowings, to make distributions. The primary purpose of these borrowings would be to mitigate the effects of short term fluctuation in our working capital that would otherwise cause volatility in our quarter to quarter distributions.

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

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

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

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

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

If at any time our general partner and its affiliates own more than 80% of the 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.

We will incur increased costs as a result of being an independent publicly traded company.

We have a limited history operating as an independent publicly traded company. As a publicly traded company, we will incur significant legal, accounting and other expenses that our predecessors did not incur as a private company. In addition, the Sarbanes-Oxley Act of 2002, as well as new rules subsequently implemented by the SEC and the NASDAQ, has required changes in corporate governance practices of publicly-traded companies. We expect these new rules and regulations to increase our legal and financial compliance costs and to make activities more time consuming and costly. For example, as a result of our becoming a publicly traded company, the general partner of our general partner is required to have at least three independent directors, create additional board committees and adopt policies regarding internal controls and disclosure controls and procedures, including the preparation of reports on internal controls over financial reporting. In addition, we will incur additional costs associated with our publicly traded company reporting requirements. We also expect these new rules and regulations to make it more difficult and more expensive for the general partner of our general partner to obtain director and officer liability insurance and it may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. As a result, it may be more difficult for the general partner of our general partner to attract and retain qualified persons to serve on its board of directors or as executive officers.

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 sale of our oil and natural gas production, less operating expenditures, such as production costs and taxes, and less estimated average capital expenditures, 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 develop or 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 develop and 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 comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to develop or 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 the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the 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 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 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, including Texas, are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we will be subject to a new entity level tax on the portion of our income that is generated in Texas beginning in our tax year ending December 31, 2007. Specifically, the Texas margin tax will be imposed at a maximum effective rate of 0.7% of our gross 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 you.

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 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, our costs of 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 United States 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 subordinated and common units sell at least 50% of the interests in our capital and profits. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income.

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

In addition to federal income taxes, you will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property, even if you do not live in any of those jurisdictions. You will likely be required to file foreign, 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, 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 United States federal, foreign, state and local tax returns.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Information regarding our properties is contained in Item 1. Business "— Our Areas of Operation," "— Our Oil and Natural Gas Data," "— Natural Gas Gathering" and "— Oil and Natural Gas Leases" contained herein.

Item 3. Legal Proceedings

We are involved in disputes or legal actions arising in the ordinary course of business. We do not believe the outcome of such disputes or legal actions will have a material adverse effect on our consolidated financial statements.

Item 4. Submissions of Matters to a Vote of Security Holders

None.

PART II

Item 5. Market for Registrant’s Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities

Our common units began trading on the NASDAQ Global Market under the symbol “EVEP” commencing with our initial public offering on September 27, 2006. At the close of business on March 15, 2007, based upon information received from our transfer agent and brokers and nominees, we had 20 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 2006:

	Price Range		Cash Distribution per Common Unit(1)
	High	Low	
Third Quarter	19.95	19.79	—
Fourth Quarter	23.81	18.89	$ 0.40

(1) On January 26, 2007, the board of directors of EV Management declared a quarterly cash distribution for the fourth quarter of 2006 of $0.40 per unit. The distribution was paid on February 14, 2007.

Cash Distributions to Unitholders

In January 2007, EV Management announced that it anticipated that it would recommend to the board of directors of EV Management that it increase our quarterly distribution to $0.46 per common unit for the quarter ending March 31, 2007, which will be payable in May 2007. In addition, in March 2007, EV Management announced that it anticipated that it would recommend to the board of directors of EV Management that it increase our quarterly distribution to $0.50 per common unit for the quarter ending June 30, 2007, which will be payable in August 2007.

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

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

Initially, our general partner will be entitled to 2% of all quarterly distributions that we make prior to our liquidation. 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. Our general partner will also hold incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 25%, of the cash we distribute from operating surplus (as defined in our partnership agreement) in excess of $0.46 per unit per quarter.

During the subordination period, the common units will have the right to receive distributions of available cash from operating surplus each quarter in an amount equal to $0.40 per common unit plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. These units are deemed “subordinated” because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received the minimum quarterly distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The practical effect of the subordinated units is to increase the likelihood that during the subordination period there will be available cash to be distributed on the common units.

The subordination period will extend until the first day of any quarter beginning after September 30, 2011 that each of the following tests are met:

- distributions of available cash from operating surplus on each of the outstanding common units, subordinated units and the 2% general partner interest equaled or exceeded the minimum quarterly distribution for each of the three consecutive, non-overlapping four quarter periods immediately preceding that date;
- the “adjusted operating surplus” (as defined in our partnership agreement) generated during each of the three consecutive, non-overlapping four quarter periods immediately preceding that date equaled or exceeded the sum of the minimum quarterly distributions on all of the outstanding common and subordinated units and the 2% general partner interest during those periods on a fully diluted basis during those periods; and
- there are no arrearages in payment of the minimum quarterly distribution on the common units.

When the subordination period expires, each outstanding subordinated unit will convert into one common unit and will then participate pro rata with the other common units in distributions of available cash. In addition, if the unitholders remove our general partner other than for cause and units held by the general partner and its affiliates are not voted in favor of such removal:

- the subordination period will end and each subordinated unit will immediately convert into one common unit;
- any existing arrearages in payment of the minimum quarterly distribution on the common units will be extinguished; and
- the general partner will have the right to convert its 2% general partner interest and its incentive distribution rights into common units or to receive cash in exchange for those interests.

In addition, if the tests for ending the subordination period are satisfied for any three consecutive, non-overlapping four quarter periods ending on or after September 30, 2009, 25% of the subordinated units will convert into an equal number of common units, and if the tests for ending the subordination period are satisfied for any three consecutive, non-overlapping four quarter periods ending after September 30, 2010, an additional 25% of the subordinated units will convert into common units. The second early conversion of subordinated units may not occur, however, until at least one year following the end of the period for the first early conversion of subordinated units.

In addition to the early conversion of subordinated units described above, all of the subordinated units will convert into an equal number of common units if the following tests are met:

- distributions of available cash from operating surplus on each of the outstanding common units, subordinated units and the 2% general partner interest equaled or exceeded $2.00 (125% of the annualized minimum quarterly distribution) for each of the two consecutive, non-overlapping four-quarter periods ending on or after September 30, 2009;
- the adjusted operating surplus generated during each of the two consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum of a distribution of $2.00 per common unit (125% of the annualized minimum quarterly distribution) on all of the outstanding common and subordinated units and the 2% general partner interest during those periods on a fully diluted basis; and
- there are no arrearages in payment of the minimum quarterly distribution on the common units.

Our partnership agreement requires that we make distributions of available cash from operating surplus for any quarter during the subordination period 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;
- *second*, 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 any arrearages in payment of the minimum quarterly distribution on the common units for any prior quarters during the subordination period;
- *third*, 98% to the subordinated unitholders, pro rata, and 2% to the general partner, until we distribute for each subordinated 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	$0.40	98%	2%
First target distribution	Up to $0.46	98%	2%
Second target distribution	Above $0.46, up to $0.50	85%	15%
Thereafter	Above $0.50	75%	25%

Unregistered Sales of Equity Securities

In connection with our formation on May 12, 2006, we issued a 1% general partnership interest to EV Energy GP for $10 and a 99% limited partnership interest to EnerVest for $990. EV Energy GP was owned by EV Management and EnerVest. Upon the closing of our initial public offering on September 29, 2006, we issued (i) 595,000 common units (before taking into account the redemption of 435,000 common units with the proceeds from the exercise of the underwriters’ option to purchase additional common units) and 3,100,000 subordinated units to EnerVest, CGAS Exploration, EnCap and EV Investors in exchange for their contribution of the ownership interests in EV Properties and (ii) the continuation of a 2% general partner interest in us and incentive distribution rights (which represent the right to receive increasing percentages of quarterly distributions in excess of specified amounts) to our general partner in exchange for their ownership interests. Each subordinated unit will convert into one common unit as described above. Each of these offerings was exempt from registration under Section 4(2) of the Securities Act of 1933. There have been no other sales of our unregistered securities during the three months ended December 31, 2006.

Use of Proceeds

Effective October 1, 2006, we closed our initial public offering of 3.9 million of our common units, and on October 26, 2006, we closed the sale of an additional 0.4 million common units, at an initial public offering price of $20.00 per unit in a firm commitment underwritten initial public offering pursuant to an S-1 Registration Statement (File No. 333-134139) declared effective by the Securities and Exchange Commission on September 25, 2006. This represented a 57.1% limited partner interest. A.G. Edwards & Sons, Inc., Raymond James & Associates, Inc., Wachovia Capital Markets, LLC and Oppenheimer & Co. Inc. served as underwriters of the offering.

The aggregate initial public offering price for the units issued in our initial public offering was approximately $86.7 million. Net proceeds, after underwriting discounts and structuring fee of approximately $6.1 million and estimated offering expenses of approximately $4.0 million, were approximately $76.6 million, of which $10.4 million was used to repay indebtedness incurred by a predecessor to finance a portion of the purchase price of certain properties contributed to us and $66.4 million was used to pay the former owners of our predecessors as part of the consideration for the interests in our predecessors contributed to us.

Item 6. Selected Financial Data

The following table shows selected financial data of us and our predecessors for the periods and as of the dates indicated. The selected financial data for the three months ended and as of December 31, 2006 are derived from our audited financial statements. The selected financial data for the nine months ended and as of September 30, 2006 and for the years ended and as of December 31, 2005, 2004 and 2003 are derived from the audited financial statements of our predecessors. The selected historical financial data for the year ended and as of December 31, 2002 are derived from the unaudited financial statements of our predecessors.

The selected financial data should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data," both contained herein.

	Successor	Predecessor(1)				
	Three Months Ended December 31, 2006(2)	Nine Months Ended September 30, 2006	Year Ended December 31, 2005(3)	2004	2003(4)	2002
Statement of Operations Data:						
Revenues:						
Oil and natural gas revenues	$ 5,548	$ 34,379	$ 45,148	$ 28,336	$ 10,370	$ 2,815
Gain (loss) on derivatives, net(6)	999	1,254	(7,194)	(1,890)	(242)	(67)
Transportation and marketing-related revenues	1,271	4,458	6,225	3,438	3,443	383
Total revenues	7,818	40,091	44,179	29,884	13,571	3,131
Operating costs and expenses:						
Lease operating expenses	1,493	6,085	7,236	6,615	3,466	2,371
Cost of purchased natural gas	1,153	3,860	5,660	3,003	2,933	—
Production taxes	109	185	292	119	65	10
Exploration expenses(5)	—	1,061	2,539	1,281	1,338	—
Dry hole costs(5)	—	354	530	440	—	—
Impairment of unproved oil and natural gas properties(5)	—	90	2,041	1,415	—	—
Asset retirement obligations accretion expense	89	129	171	160	67	—
Depreciation, depletion and amortization	1,180	4,388	4,409	4,135	1,837	87
General and administrative expenses	2,043	1,449	899	1,061	1,069	202
Management fees	—	42	117	94	69	—
Total operating costs and expenses	6,067	17,643	23,894	18,323	10,844	2,670
Operating income	1,751	22,448	20,285	11,561	2,727	461
Other income (expense), net	1,616	(229)	(428)	12	264	(144)
Income before income taxes and equity in income (loss) of affiliates	3,367	22,219	19,857	11,573	2,991	317
Income taxes	—	(5,809)	(5,349)	(2,521)	(317)	—
Equity in income (loss) of affiliates	—	164	565	(621)	3	—
Net income	$ 3,367	$ 16,574	$ 15,073	$ 8,431	$ 2,677	$ 317
General partner's interest in net income	$ 67					
Limited partners' interest in net income	$ 3,300					
Net income per limited partner unit:						
Common units (basic and diluted)	$ 0.43					
Subordinated units (basic and diluted)	$ 0.43					
Cash distribution per common unit	$ —					
Financial Position (at end of period):						
Working capital	$ 12,006	$ 9,190	$ (642)	$ 3,094	$ (7,557)	$ 248
Total assets	132,689	95,749	77,351	58,801	57,132	2,486
Long-term debt	28,000	10,350	10,500	2,850	3,050	3,050
Owners' equity	96,253	63,240	40,910	41,215	34,756	(748)

(1) Our predecessors' combined financial statements include the results of EV Properties and CGAS Exploration, combined as entities under common control. EV Properties was formed in April 2006 by EnerVest, EV

Investors and EnCap. In connection with the formation of EV Properties, EnerVest contributed interests in two partnerships, EnerVest Production Partners, which owned the Northern Louisiana properties, and EnerVest WV, which owned the West Virginia properties. EnCap contributed $16 million in cash to EV Properties which was used to purchase the interest of an unaffiliated limited partner in EnerVest WV.

(2) Includes the results of the Five States acquisition of oil and natural gas properties in the Mid-Continent area from December 15, 2006 (date of acquisition) to December 31, 2006.

(3) Includes the results of an acquisition by our predecessors of oil and natural gas properties in the Monroe Field in March 2005.

(4) Includes the results of CGAS Exploration since its acquisition in August 2003.

(5) Exploration expenses, dry hole costs and impairment of unproved properties were incurred by CGAS Exploration with respect to properties we did not acquire.

(6) Our predecessors accounted for their derivatives as cash flow hedges in accordance with SFAS No. 133. Accordingly, the changes in fair value of the derivatives were reported in other comprehensive income (“OCI”) and reclassified to net income in the periods in which the contracts were settled. As of October 1, 2006, we elected not to designate our derivatives as hedges in accordance with SFAS No. 133. The amount in OCI at that date related to derivatives that previously were designated and accounted for as cash flow hedges continues to be deferred until the underlying production is produced and sold, at which time amounts are reclassified from OCI and reflected as a component of revenues. Changes in the fair value of derivatives that existed at October 1, 2006 and any derivatives entered thereafter are no longer deferred in OCI, but rather are recorded immediately to net income as “Gain on mark-to-market derivatives, net”, which in included in “Other income (expense), net” in our consolidated statement of operations.

Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations

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

Overview

We are a Delaware limited partnership formed in April 2006 by EnerVest to acquire, produce and develop oil and natural gas properties. We consummated the acquisition of our predecessors and an initial public offering of our common units effective October 1, 2006. Our general partner is EV Energy GP and the general partner of our general partner is EV Management.

Our predecessors were:

- EV Properties, a limited partnership that owned oil and natural gas properties and related assets in the Monroe Field in Northern Louisiana and in the Appalachian Basin in West Virginia, and
- CGAS Exploration, a corporation that owned oil and natural gas properties and related assets in the Appalachian Basin, primarily in Ohio.

EV Properties was formed in the second quarter of 2006 by EnerVest, as general partner, and EV Investors and EnCap, as limited partners, to acquire the business of the following partnerships which were controlled by EnerVest:

- EnerVest Production Partners which owned oil and natural gas properties and related assets in the Monroe Field in Northern Louisiana, and
- EnerVest WV which owned oil and natural gas properties and related assets in West Virginia.

In April 2006, EnerVest and its subsidiaries contributed all of the general and limited partnership interests in EnerVest Production Partners and the general partnership interest in EnerVest WV to EV Properties in exchange for general and limited partnership interests in EV Properties. In addition, EnCap contributed a net $16.0 million in cash to EV Properties in exchange for limited partnership interests in EV Properties, which then used the $16.0 million contribution from EnCap to purchase the limited partnership interests in EnerVest WV. As of result of these transactions, EnerVest and EnCap owned EV Properties and EV Properties owned all of the interests in the partnerships that owned the oil and natural gas properties and related assets in West Virginia and Louisiana.

As a result of these transactions, the combined operations of our predecessors reflect the operations of the following entities:

- the combined operations of EnerVest Production Partners, EnerVest WV and CGAS Exploration for periods before May 12, 2006, and
- the combined operations of EV Properties and CGAS Exploration from May 12, 2006 through September 30, 2006.

In connection with our initial public offering, we acquired substantially all of the assets and operations of EV Properties and approximately one-half of the assets and operations of CGAS Exploration. The financial statements of our predecessors, therefore, include substantial operations that we did not acquire. In addition,

- CGAS Exploration incurred substantial expenses related to exploration activities, which we do not plan to do;
- the contracts under which our predecessors reimbursed EnerVest for general and administrative costs were different than the contracts under which we will reimburse EnerVest in the future; and
- our predecessors did not incur the additional costs of being a public company.

Our Initial Public Offering

Effective October 1, 2006, we completed our initial public offering of 3.9 million common units at a price of $20.00 per unit, and on October 26, 2006, we closed the sale of an additional 0.4 million common units at a price per unit of $20.00 pursuant to the exercise of the underwriters' over-allotment option. Net proceeds after underwriting discounts, structuring fees and offering costs from the sale of the common units were approximately $76.6 million. At the closing of our initial public offering, the partners of EV Properties transferred their ownership interests in EV Properties to us in exchange for common units, subordinated units and cash payments totaling $28.1 million. In addition, at the closing of our initial public offering, CGAS Exploration formed a limited partnership and contributed all of its wells producing from shallow formations as well as the undeveloped properties with proved undeveloped locations or other drilling potential in the shallow formations to the partnership in exchange for a limited partner interest. CGAS Exploration then contributed this limited partner interest to us in exchange for common units, subordinated units and a cash payment of $38.3 million. CGAS Exploration retained its properties in the deeper formations following the offering.

The remainder of the proceeds from our initial public offering was used to repay $10.4 million of indebtedness incurred by our predecessors and to pay approximately $4.0 million of expenses associated with our initial public offering and related formation transactions.

The Five States Acquisition

On December 15, 2006, we acquired oil and natural gas properties in Louisiana, Texas and Oklahoma from Five States Energy Company, LLC for $27.6 million. Estimated net proved reserves attributable to these properties at December 31, 2006 were 14.8 Bcfe, of which 8.9 Bcfe were natural gas. The acquisition was funded with borrowings under our credit facility.

Issuance of Common Units in 2007

In February 2007, we issued 3.9 million common units to institutional investors in a private placement for net proceeds of $100.0 million, including a $2.0 million contribution by our general partner to maintain its 2% interest in us. We used the proceeds of this issuance to repay all of the indebtedness under our credit facility. The borrowings repaid with the proceeds of the offering represented the borrowings made to finance our Five States and Michigan acquisitions.

Our Assets

At December 31, 2006, our oil and natural gas properties had estimated net proved reserves of 2.0 MMBbls of oil and 49.4 Bcf of natural gas, and a present value of future net cash flows, discounted at 10%, or standardized measure, of $105.0 million. We also have a gathering system which primarily gathers and transports natural gas production from substantially all of our producing wells to larger gathering systems and intrastate and interstate pipelines. In addition, we gather, market and transport a small amount of natural gas for third parties.

In January 2007, we acquired natural gas properties in Michigan from an institutional partnership managed by EnerVest for $71.4 million. Estimated net proved reserves attributable to these properties at December 31, 2006 were 56.3 Bcfe. We financed the acquisition with borrowings under our existing credit facility.

In March 2007, we acquired additional natural gas properties in the Monroe Field in Louisiana from an institutional partnership managed by EnerVest for $95.3 million. Estimated net proved reserves attributable to these properties at December 31, 2006 were 65.2 Bcfe, all of which were natural gas. We financed the acquisition with borrowings under our existing credit facility.

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 and natural gas production;
- our ability to hedge commodity prices;
- the amount of oil and natural gas we produce; and
- the level of our operating and administrative costs.

Oil and natural gas prices have been, and are expected to be, volatile. Prices for oil and natural gas fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of factors beyond our control. Factors affecting the price of oil include the lack of excess productive capacity, geopolitical activities, worldwide supply disruptions, worldwide economic conditions, weather conditions, actions taken by the Organization of Petroleum Exporting Countries and fluctuating currency exchange rates. Factors affecting the price of natural gas include North American weather conditions, industrial and consumer demand for natural gas, storage levels of natural gas and the availability and accessibility of natural gas deposits in North America.

As of December 31, 2006, we are a party to derivative agreements, and we intend to enter into derivative agreements in the future to reduce the impact of oil and natural gas price volatility on our cash flows. By removing a significant portion of our price volatility on our future oil and natural gas production, we have mitigated, but not eliminated, the potential effects of changing oil and natural gas prices on our cash flows from operations for those periods.

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, we face the challenge of natural production declines. As initial reservoir pressures are depleted, production from a given well decreases. We attempt to overcome this natural decline by drilling to find additional reserves and acquiring more reserves than we produce. Our future growth will depend on our ability to continue to add reserves in excess of production. We will maintain our focus on 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 the rate of increase in our production, which may have an adverse effect on our revenues and, as a result, cash available for distribution.

Higher oil and natural gas prices have led to higher demand for drilling rigs, operating personnel and field supplies and services, and have caused increases in the costs of these goods and services. To date, the higher sales prices have more than offset the higher drilling and operating expenses. We focus our efforts on increasing oil and natural gas reserves and production while controlling costs at a level that is appropriate for long-term operations. Our future cash flows from operations are dependent on our ability to manage our overall cost structure.

Critical Accounting Estimates

The preparation of our 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. 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. 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 estimates 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 estimates used in the preparation of our consolidated financial statements. In addition, there are other items within our consolidated financial statements that require estimation.

Oil and Natural Gas Properties

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

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

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

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

We assess our proved oil and natural gas properties for possible impairment whenever events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. Such events include a projection of future oil and natural gas reserves that will be produced from a field, the timing of this future production, future costs to produce the oil and natural gas and future inflation levels. If the carrying amount of a property exceeds the sum of the estimated undiscounted future net cash flows, we recognize an impairment expense equal to the difference between the carrying value and the fair value of the property, which is estimated to be the expected present value of the future net cash flows from proved reserves, utilizing a risk-free rate of return. Estimated future net cash flows are based on management’s expectations for the future and include estimates of oil and natural gas reserves and future commodity prices and operating costs. Downward revisions in estimates of reserve quantities or expectations of falling commodity prices or rising operating costs could result in a reduction in undiscounted future cash flows and could indicate a property impairment.

Estimates of Oil and Natural Gas Reserves

Our estimates of proved oil and natural gas reserves are based on the quantities of oil and natural gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. 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. As such, our independent reserve engineers review and revise our reserve estimates at least annually.

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 our oil and natural gas properties, the quantity of reserves could significantly impact our depreciation, depletion and amortization expense. Our reserves are also the basis of our supplemental oil and natural gas disclosures.

Accounting for Derivatives

We use derivatives to hedge against the variability in cash flows associated with the forecasted sale of our anticipated future oil and natural gas production. We generally hedge a substantial, but varying, portion of our anticipated oil and natural gas production for the next 12-36 months. We do not use derivative instruments 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 predecessors had elected to apply hedge accounting to its derivatives, which allowed them to defer the impact of any changes in fair value of derivatives and record only realized gains and losses when the hedged volumes were produced and sold. Our 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 and the time value of options. 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 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.

SFAS No. 143, *Accounting for Asset Removal Obligations,* together with the related FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations, an Interpretation of FASB Statement No. 143,* requires that the discounted fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred with the associated asset retirement cost capitalized as past of the carrying cost of the oil and natural gas asset. In periods subsequent to initial measurement of the asset retirement obligation, we recognize period to period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimates.

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 liability, a corresponding adjustment is made to the oil and natural gas property balance.

Results of Operations

	Combined	Successor(1)	Predecessor		
	Year Ended December 31, 2006	Three Months Ended December 31, 2006	Nine Months Ended September 30, 2006	Year Ended December 31, 2005	Year Ended December 31, 2004
Revenues:					
Oil and natural gas revenues	$ 39,927	$ 5,548	$ 34,379	$ 45,148	$ 28,336
Gain (loss) on derivatives, net	2,253	999	1,254	(7,194)	(1,890)
Transportation and marketing-related revenues	5,729	1,271	4,458	6,225	3,438
Total revenues	47,909	7,818	40,091	44,179	29,884
Operating costs and expenses:					
Lease operating expenses	7,578	1,493	6,085	7,236	6,615
Cost of purchased natural gas	5,013	1,153	3,860	5,660	3,003
Production taxes	294	109	185	292	119
Exploration expenses	1,061	—	1,061	2,539	1,281
Dry hole costs	354	—	354	530	440
Impairment of unproved oil and natural gas properties	90	—	90	2,041	1,415
Asset retirement obligations accretion expense	218	89	129	171	160
Depreciation, depletion and amortization	5,568	1,180	4,388	4,409	4,135
General and administrative expenses	3,492	2,043	1,449	899	1,061
Management fees	42	—	42	117	94
Total operating costs and expenses	23,710	6,067	17,643	23,894	18,323
Operating income	24,199	1,751	22,448	20,285	11,561
Other income (expense), net:					
Interest expense	(707)	(134)	(573)	(632)	(327)
Gain on mark-to-market derivatives, net	1,719	1,719	—	—	—
Other income, net	375	31	344	204	339
Total other income (expense), net	1,387	1,616	(229)	(428)	12
Income before income taxes and equity in income (loss) of affiliates	$ 25,586	$ 3,367	$ 22,219	$ 19,857	$ 11,573
Production data:					
Oil (MBbls)	165	18	147	174	153
Natural gas (MMcf)	3,900	625	3,275	3,901	3,589
Net production (MMcfe)	4,893	734	4,159	4,947	4,504
Average sales price per unit:					
Oil (Bbl)	$ 63.54	$ 56.65	$ 64.38	$ 53.70	$ 39.33
Natural gas (Mcf)	7.54	7.24	7.60	9.17	6.22
Average unit cost per Mcfe:					
Production costs:					
Lease operating expenses	$ 1.55	$ 2.04	$ 1.46	$ 1.46	$ 1.47
Production taxes	0.06	0.15	0.04	0.06	0.03
Total	1.61	2.19	1.50	1.52	1.50
Depreciation, depletion and amortization	1.14	1.61	1.06	0.89	0.92
General and administrative expenses	0.72	2.78	0.36	0.21	0.26

(1) In connection with our initial public offering, we acquired substantially all of the assets and operations of EV Properties and approximately one-half of the assets and operations of CGAS Exploration. The financial statements of our predecessors, therefore, include substantial operations that we did not acquire. In addition,

- CGAS Exploration incurred substantial expenses related to exploration activities, which we do not plan to do;
- the contracts under which our predecessors reimbursed EnerVest for general and administrative costs were different than the contracts under which we will reimburse EnerVest in the future; and
- our predecessors did not incur the additional costs of being a public company.

Year Ended December 31, 2006 Compared with the Year Ended December 31, 2005

Our results of operations for the year ended December 31, 2006 are derived from the combination of the results of the combined operations of our predecessors for the nine months ended September 30, 2006 and the results of our operations for the three months ended December 31, 2006. The combined results of operations for the year ended December 31, 2006 are unaudited and do not necessarily represent the results that would have been achieved during this period had the business been operated by us for the entire year.

Oil and natural gas revenues for the year ended December 31, 2006 totaled $39.9 million, a decrease of 12% compared with the year ended December 31, 2005. Approximately 89%, or $4.6 million, of this decrease was attributable to decreased natural gas prices partially offset by increased oil prices. Natural gas prices for 2006 averaged $7.54 per Mcf compared with an average of $9.17 per Mcf for 2005, and oil prices for 2006 averaged $63.54 per Bbl compared with an average of $53.70 per Bbl for 2005. The remainder of the decrease was primarily due to lower production in the Appalachian Basin as a result of the oil and natural gas properties that we did not acquire from CGAS Exploration offset by increased production from our Monroe Field properties and production from the oil and natural gas properties that we acquired in the Five States acquisition on December 15, 2006.

Due to fluctuations in the commodity market, gain (loss) on derivatives, net was $2.3 million for 2006 compared with $(7.2) million for 2005. Our predecessors accounted for their derivatives as cash flow hedges in accordance with SFAS No. 133 and, as a result, the changes in fair value of the derivatives were reported in OCI and reclassified to net income in the periods in which the contracts were settled. Effective October 1, 2006, we elected not to designate our derivatives as hedges in accordance with SFAS No. 133. The amount in OCI at that date related to derivatives that previously were designated and accounted for as cash flow hedges continues to be deferred until the underlying production is produced and sold, at which time the amounts are reclassified from OCI and reflected as a component of revenues. Changes in the fair value of derivatives that existed at October 1, 2006 and any derivatives entered into thereafter are no longer deferred in OCI, but rather are recorded immediately to net income as “Gain on mark-to-market derivatives, net”.

Transportation and marketing-related revenues for 2006 decreased $0.5 million, or 8%, compared with 2005 primarily due to lower prices for natural gas transported through our gathering systems.

Lease operating expenses for 2006 increased $0.3 million, or 5%, compared with 2005 as of result of (i) $0.1 million in lease operating expenses for the oil and natural gas properties that we acquired in the Five States acquisition, (ii) $0.2 million in adjustments to the value of our oil inventory and (iii) increased costs of material and labor, offset by a decrease in lease operating expenses related to the oil and natural gas properties that we did not acquire from CGAS Exploration. Lease operating expenses per Mcfe produced were $1.55 in 2006 compared with $1.46 in 2005.

The cost of purchased natural gas for 2006 decreased by $0.6 million, or 11%, compared with 2005 primarily due to lower prices for natural gas.

Exploration expenses totaled $1.1 million in 2006, a decrease of 58% compared with 2005. These expenses principally consist of expenditures for exploratory and confirmation seismic incurred by our predecessors to explore the deep formations in the Ohio area properties of CGAS Exploration that we did not acquire.

Depreciation, depletion and amortization for 2006 totaled $5.6 million, or $1.14 per Mcfe, compared with $4.4 million, or $0.89 per Mcfe, for 2005. The increase was primarily due to an increase in depreciable property from our Five States acquisition and an increase in the basis of the depreciable property that we acquired from CGAS Exploration.

General and administrative expenses include the costs of administrative employees and related benefits, management fees paid to EnerVest, professional fees and other costs not directly associated with field operations. General and administrative expenses for 2006 totaled $3.5 million, an increase of $2.6 million, or 288%, compared with 2005. General and administrative expenses were $0.72 per Mcfe in 2006 compared with $0.21 per Mcfe in 2005. These increases are primarily the result of (i) $0.3 million of fees paid to EnerVest under the omnibus agreement, (ii) $1.1 million of audit and tax fees related to the audit of our December 31, 2006 financials and the preparation of our 2006 tax returns, all of which was accrued during the three months ended December 31, 2006, (iii) $0.5 million of payroll expenses for EV Management employees and (iv) an overall increase in costs related to being a public partnership.

As a result of the change in how we account for derivatives, gain on mark-to-market derivatives, net for 2006 included $1.8 million of realized gains and $0.1 million of unrealized losses on the mark-to-market of derivatives.

Year Ended December 31, 2005 Compared with the Year Ended December 31, 2004

Oil and natural gas revenues for 2005 totaled $45.1 million, an increase of 59% compared with 2004. Approximately 76%, or $12.8 million, of this increase was attributable to higher oil and natural gas prices. Oil prices for 2005 averaged $53.70 per Bbl compared with $39.33 per Bbl for 2004. Natural gas prices for 2005 averaged $9.17 per Mcf compared $6.22 per Mcf for 2004. The remainder of the increase was due to increased production primarily due to the acquisition of properties in the Monroe field in March 2005.

Due to fluctuations in the commodity market, realized net loss on oil and natural gas derivatives was $7.2 million for 2005 compared with $1.9 million for 2004.

Transportation and marketing-related revenues for 2005 increased $2.8 million, or 81%, compared with 2004 primarily due to the acquisition of additional gathering systems as part of the acquisition of properties in the Monroe Field in March 2005.

Lease operating expenses for 2005 increased $0.6 million, or 9%, compared with 2004 primarily due to increased costs associated with operations of the additional properties we acquired in the Monroe Field in 2005 and increased costs of materials and labor partially offset by a reduction in personnel costs as the operations of CGAS Exploration, which was acquired in 2003, were integrated into our operations. Lease operating expense per Mcfe produced was $1.46 in 2005 compared with $1.47 during 2004.

The cost of purchased natural gas for 2005 increased by $2.7 million, or 88%, compared with 2004 primarily due to the additional natural gas purchased through the gathering system acquired in March 2005.

Exploration expenses totaled $2.5 million in 2005, an increase of 98% compared with 2004. These expenses principally consist of expenditures for exploratory and confirmation seismic incurred to explore the deep formations in the Ohio area properties of CGAS Exploration that we did not acquire.

Impairment of unproved properties totaled $2.0 million and $1.4 million for 2005 and 2004, respectively. All of these impairment charges related to lease acreage costs incurred by CGAS Exploration and resulted from either unsuccessful drilling results or a decision not to pursue further exploration of deeper reservoir targets.

Depreciation, depletion and amortization for 2005 increased $0.3 million, or 7%, compared with 2004 primarily due to increases in depreciable property from development drilling in the Ohio area properties. On an Mcfe produced basis, depreciation, depletion and amortization expense was $0.89 in 2005 and $0.92 in 2004.

General and administrative expenses include the costs of administrative employees and related benefits, management fees paid to EnerVest under agreements between EnerVest and our predecessors, professional fees and other costs not directly associated with field operations. General and administrative expenses for 2005 decreased $0.2 million, or 15%, compared with 2004. This decrease was primarily due to significant savings following the consolidation and integration of CGAS Exploration’s operations in 2004. On a per Mcfe of production basis, general and administrative expenses were $0.21 and $0.26 in 2005 and 2004, respectively.

LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of liquidity and capital have been issuances of equity 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, distributions to our partners and working capital needs. For 2007, we believe that cash on hand, the sale of common units in February 2007, net cash flows generated from operations and borrowings under our credit facility will be adequate to fund our capital budget and satisfy our short-term liquidity needs. We may also utilize various financing sources available to us, including the issuance of additional common units through public offerings or private placements, to fund our long-term liquidity needs. Our ability to complete future offerings of our common units and the timing of these offerings will depend upon various factors including prevailing market conditions and our financial condition.

Available Credit Facility

We have a $150.0 million senior secured credit facility that expires in September 2011. Borrowings under the facility are secured by a first priority lien on substantially all of the assets of EV 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, so long as outstanding borrowings are less than 90% of the borrowing base, for funding distributions to partners. We also may use up to $20.0 million of available borrowing capacity for letters of credit. The facility contains certain covenants which, among other things, require the maintenance of a current ratio (as defined in the facility) of greater than 1.00 and a ratio of total debt to earnings plus interest expense, taxes, depreciation, depletion and amortization expense and exploration expense of no greater than 4.0 to 1.0. As of December 31, 2006, we were in compliance with all of the facility covenants.

Borrowings under the facility will bear interest at a floating rate based on, at our election, a base rate or the London Inter-Bank Offered Rate plus applicable premiums based on the percent of the borrowing base that we have outstanding. The amount of borrowings that we may have outstanding under the facility is subject to a borrowing base calculation which is calculated semi-annually and in connection with material acquisitions or divestitures of properties. The current borrowing base under the facility is $111.0 million. At December 31, 2006, we had $28.0 million outstanding under the facility.

Cash Flows

Cash flows provided (used) by type of activity were as follows for the years ended December 31, 2006, 2005 and 2004:

	Successor	Predecessor		
	Three Months Ended December 31, 2006	Nine Months Ended September 30, 2006	Year Ended December 31, 2005	Year Ended December 31, 2004
Operating activities	$ 2,863	$ 20,114	$ 27,979	$ 16,704
Investing activities	(70,688)	(7,041)	(17,797)	(3,821)
Financing activities	69,700	(17,330)	(4,695)	(12,160)

Operating Activities

Cash flows from operating activities provided $2.9 million in the three months ended December 31, 2006 and $20.1 million in the nine months ended September 30, 2006. Cash flows from operating activities provided $28.0 million in 2005 compared with $16.7 million in 2004. This increase was primarily due to higher oil and natural gas prices and improved management of our working capital position.

Investing Activities

Our principal recurring investing activity is the acquisition and development of oil and natural gas properties. During the three months ended December 31, 2006, we spent $69.5 million for the acquisition of our predecessors and for the Five States acquisition and $1.2 million for the development of oil and natural gas properties, primarily related to development drilling on our Appalachian Basin properties. During the nine months ended September 30, 2006, our predecessors spent $6.9 million for the development of oil and natural gas properties, primarily related to development drilling on the Ohio properties. During 2005, our predecessors spent $11.2 million for the acquisition of oil and natural gas properties, which included $10.7 million related to the acquisition of oil and natural gas properties in the Monroe Field in Northern Louisiana, and spent $5.6 million for the development of oil and natural gas properties, primarily related to development drilling on the Ohio properties. During 2004, our predecessors spent $5.7 million for the acquisition and development of oil and natural gas properties and had proceeds of $2.4 million from the sale of non-strategic assets.

Financing Activities

During the three months ended December 31, 2006, we received proceeds of $81.1 million from our initial public offering. From these net proceeds, we paid offering costs of $4.4 million, distributions of $24.1 million to the owners of the predecessors and repaid $10.4 million of borrowings outstanding under our predecessors' credit facility. In addition, we borrowed $28.0 million under our credit facility to finance our Five States acquisition.

During the nine months ended September 30, 2006, our predecessors received contributions from partners of $16.0 million and paid distributions and dividends to partners of $33.3 million. In 2005, contributions from partners totaled $2.0 million, distributions and dividends to partners totaled $14.2 million and borrowings to acquire properties in the Monroe field totaled $8.7 million. In 2004, distributions and dividends to partners totaled $2.1 million and repayments of related party advances totaled $10.1 million.

Cash Requirements

We currently expect 2007 spending for the development of our oil and natural gas properties to be between $7.5 million and $8.5 million. In 2007, we expect to make distributions of approximately $20.4 million to our unitholders based on our current and anticipated quarterly distribution rates per common and subordinated unit and the number of units outstanding, including the common units sold in February 2007.

We are actively engaged in the acquisition of oil and natural gas properties. We expect to continue to acquire oil and natural gas properties during 2007. We plan to finance the acquisitions with borrowings under our credit facility and issuances of equity and debt securities.

We do not believe there are any other material trends, demands, commitments, events or uncertainties that would have, or are reasonably likely to have, a material impact on our financial condition and liquidity.

Contractual Obligations

In the table below, we set forth our contractual cash obligations as of December 31, 2006. Some of the figures we include in this table are based on our estimates and assumptions about these obligations, including their duration, anticipated actions by third parties and other factors. The contractual cash obligations we will actually pay in future periods may vary from those reflected in the table because the estimates and assumptions are subjective. Amounts in the table represent obligations where both the timing and amount of payment streams are known.

	Payments Due by Period (Amounts in Thousands)				
	Total	Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
Total debt	$ 28,000	$ —	$ —	$ 28,000	$ —
Estimated interest payments(1)	9,283	1,954	3,909	3,420	—
Purchase obligation(2)	4,725	2,265	2,460	—	—
Other long-term liabilities(3)	5,188	—	—	—	5,188
Total	$ 47,196	$ 4,219	$ 6,369	$ 31,420	$ 5,188

(1) Amounts represent the expected cash payments for interest based on the debt outstanding and the effective interest rate as of December 31, 2006.

(2) Amounts represent payments to be made under our omnibus agreement with EnerVest. While these payments will continue for periods subsequent to December 31, 2008, no amounts are shown as they cannot be quantified.

(3) Amounts represent estimated asset retirement obligations.

Off-Balance Sheet Arrangements

As of December 31, 2006, we had no off-balance sheet arrangements.

NEW ACCOUNTING STANDARDS

In February 2006, the Financial Accounting Standards Board ("FASB") issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments*, to simplify and make more consistent the accounting for certain financial instruments. SFAS No. 155 amends SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, to permit fair value remeasurement for any hybrid financial instrument with an embedded derivative that would otherwise require bifurcation, provided that the whole instrument is accounted for on a fair value basis. SFAS No.

155 also amends SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*, to allow a qualifying special purpose entity to hold a derivative financial instrument that pertains to a beneficial interest other than another derivative financial instrument. SFAS No. 155 is effective for all financial instruments acquired or issued after the beginning of an entity's first fiscal year that begins after September 15, 2006. We adopted SFAS No. 155 on January 1, 2007, and there was no impact on our consolidated financial statements.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*, to provide guidance for using fair value to measure assets and liabilities. SFAS No. 157 establishes a fair value hierarchy and clarifies the principle that fair value should be based on assumptions market participants would use when pricing the asset or liability. SFAS No. 157 also requires expanded disclosure of the effect on earnings for items measured using unobservable data. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. We will adopt SFAS No. 157 on January 1, 2008, and we do not expect the adoption to have a material impact on our consolidated financial statements.

In September 2006, the SEC issued Staff Accounting Bulletin ("SAB") No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*. SAB 108 addresses how the effects of prior year uncorrected misstatements should be considered when quantifying misstatements in current year financial statements. SAB 108 requires companies to quantify misstatements using a balance sheet and income statement approach and to evaluate whether either approach results in quantifying an error that is material in light of relevant quantitative and qualitative factors. We adopted SAB 108 on December 31, 2006, and there was no impact on our consolidated financial statements.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115*. SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. Unrealized gains and losses on items for which the fair value option has been selected are reported in earnings. SFAS No. 159 also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. We will adopt SFAS No. 159 on January 1, 2008, and we have not yet determined the impact, if any, on our consolidated financial statements.

FORWARD-LOOKING STATEMENTS

This Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Exchange Act (each a "forward-looking statement"). 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 projection of results of operations or of financial condition or state other "forward-looking" information.

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.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

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

Commodity Price Risk

Our major market risk exposure is to oil and natural gas prices which 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, energy financial instruments to reduce our risk of changes in the prices of oil and natural gas.

Pursuant to our risk management policy, we engage in these activities as a hedging mechanism against price volatility associated with pre-existing or anticipated physical oil and natural gas to protect their profit margins.

As of December 31, 2006, we had entered into swap agreements for oil and natural gas with the following terms:

Period Covered	Index	Hedged Volume per Day (Bbl or MMBtu)	Weighted Average Fixed Price	Weighted Average Floor Price	Weighted Average Ceiling Price
Oil:					
Costless Collar – 2008	WTI	125	$	$ 62.000	$ 73.950
Costless Collar – 2009	WTI	125		62.000	73.900
Swap – 2007	WTI	125	66.300		
Swap – 2007	WTI	125	76.400		
Natural Gas:					
Costless Collar – 2008		1,000		7.500	9.850
Costless Collar – 2009		1,000		7.500	8.800
Swap – 2007	Dominion Appalachia	3,100	10.265		
Swap – 2008	Dominion Appalachia	2,700	9.750		
Swap – 2007	NYMEX	1,500	9.820		
Swap – 2007	NYMEX	500	10.000		
Swap – 2008	NYMEX	1,500	9.360		
Swap – 2008	NYMEX	500	9.500		

We do not designate these or future derivative agreements as hedges for accounting purposes pursuant to SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended. Accordingly, the changes in the fair value of these agreements are recognized currently in earnings. At December 31, 2006, the fair value associated with these derivative agreements is an asset of $8.2 million.

Interest Rate Risk

The following tables set forth the required cash payments for our long-term debt and the related weighted average effective interest rate as of December 31 2006 and 2005 (dollars in thousands):

	As of December 31, 2006							
	Expected Maturity Date							
	2007	2008	2009	2010	2011	Thereafter	Total	Fair Value
Long-term debt:								
Variable					$ 28,000		$ 28,000	$ 28,000
Average interest rate					6.98 %		6.98 %	

	As of December 31, 2005							
	Expected Maturity Date							
	2007	2008	2009	2010	2011	Thereafter	Total	Fair Value
Long-term debt:								
Variable		$ 10,500					$ 10,500	$ 10,500
Average interest rate		5.77 %					5.77 %	

Item 8. Financial Statements and Supplementary Data

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 sheet of EV Energy Partners, L.P. and subsidiaries (the "Partnership") as of December 31, 2006 (Successor), and combined balance sheets of the Combined Predecessor Entities (the "Entities"), as defined in Note 1 to the consolidated/combined financial statements, as of December 31, 2005 (Predecessor), and the related consolidated statements of operations, cash flows, and changes in owners' equity of the Partnership for the three months ended to December 31, 2006 (Successor), and combined statements of operations, cash flows, and changes in owners' equity of the Entities for the nine months ended September 30, 2006, and for the years ended December 31, 2005 and 2004 (Predecessor). These consolidated/combined financial statements are the responsibility of the Partnership's management and the Entities' management. Our responsibility is to express an opinion on these consolidated/combined financial statements based on our audits.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Partnership and the Entities are not required to have, nor were we engaged to perform, an audit of their internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's or the Entities' internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provides a reasonable basis for our opinion.

In our opinion, such consolidated and combined financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2006 (Successor) and of the Entities as of December 31, 2005 (Predecessor), respectively, and the results of their operations and their cash flows for the three months ended December 31, 2006 (Successor), nine months ended September 30, 2006, and for the years ended December 31, 2005 and 2004 (Predecessor) in conformity with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
April 2, 2007

EV ENERGY PARTNERS, L.P.

BALANCE SHEETS
(In thousands)

	Successor December 31, 2006 (consolidated)	Predecessor December 31, 2005 (combined)
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,875	$ 7,159
Accounts receivable:		
Oil and natural gas sales	4,608	8,082
Related party	1,996	—
Other	56	530
Interest and commodity hedge asset-related party	—	61
Commodity hedge asset	5,929	—
Deferred income taxes	—	1,875
Prepaid expenses	350	373
Other current assets	440	244
Total current assets	15,254	18,324
Oil and natural gas properties, net of accumulated depreciation, depletion and amortization; December 31, 2006, $4,092; December 31, 2005, $9,706	114,401	57,037
Other property, net of accumulated depreciation and amortization; December 31, 2006, $195; December 31, 2005, $785	283	563
Long-term commodity hedge asset	2,286	—
Other assets	465	1,427
Total assets	$ 132,689	$ 77,351
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 3,248	$ 5,968
Due to affiliates	—	5,575
Commodity hedge liability-related party	—	5,228
Commodity hedge liability	—	954
Income taxes	—	1,171
Other current liabilities	—	70
Total current liabilities	3,248	18,966
Asset retirement obligations	5,188	2,752
Long-term debt	28,000	10,500
Deferred income taxes	—	4,205
Long-term commodity hedge liability-related party	—	18
Commitments and contingencies		
Owners' equity:		
Predecessors	—	45,178
Common unitholders	77,701	—
Subordinated unitholders	10,830	—
General partner interest	3,379	—
Accumulated other comprehensive income (loss)	4,343	(4,268)
Total owners' equity	96,253	40,910
Total liabilities and owners' equity	$ 132,689	$ 77,351

See accompanying notes to consolidated/combined financial statements.

EV ENERGY PARTNERS, L.P.

STATEMENTS OF OPERATIONS
(In thousands, except per unit data)

	Successor	Predecessor		
	Three Months Ended December 31, 2006	Nine Months Ended September 30, 2006	Year Ended December 31, 2005	Year Ended December 31, 2004
	(consolidated)	(combined)		
Revenues:				
Oil and natural gas revenues	$ 5,548	$ 34,379	$ 45,148	$ 28,336
Gain (loss) on derivatives, net	999	1,254	(7,194)	(1,890)
Transportation and marketing-related revenues	1,271	4,458	6,225	3,438
Total revenues	7,818	40,091	44,179	29,884
Operating costs and expenses:				
Lease operating expenses	1,493	6,085	7,236	6,615
Cost of purchased natural gas	1,153	3,860	5,660	3,003
Production taxes	109	185	292	119
Exploration expenses	—	1,061	2,539	1,281
Dry hole costs	—	354	530	440
Impairment of unproved oil and natural gas properties	—	90	2,041	1,415
Asset retirement obligations accretion expense	89	129	171	160
Depreciation, depletion and amortization	1,180	4,388	4,409	4,135
General and administrative expenses	2,043	1,449	899	1,061
Management fees	—	42	117	94
Total operating costs and expenses	6,067	17,643	23,894	18,323
Operating income	1,751	22,448	20,285	11,561
Other income (expense), net:				
Interest expense:				
Third party	(134)	(573)	(625)	(158)
Related party	—	—	(7)	(169)
Gain on mark-to-market derivatives, net	1,719	—	—	—
Other income, net	31	344	204	339
Total other income (expense), net	1,616	(229)	(428)	12
Income before income taxes and equity in income (loss) of affiliates	3,367	22,219	19,857	11,573
Income taxes	—	(5,809)	(5,349)	(2,521)
Equity in income (loss) of affiliates	—	164	565	(621)
Net income	$ 3,367	$ 16,574	$ 15,073	$ 8,431
General partner's interest in net income	$ 67			
Limited partners' interest in net income	$ 3,300			
Net income per limited partner unit:				
Common units (basic and diluted)	$ 0.43			
Subordinated units (basic and diluted)	$ 0.43			
Weighted average limited partner units outstanding:				
Common units (basic and diluted))	4,495			
Subordinated units (basic and diluted)	3,100			

See accompanying notes to consolidated/combined financial statements.

EV ENERGY PARTNERS, L.P.

STATEMENTS OF CASH FLOWS
(In thousands)

	Successor	Predecessor		
	Three Months Ended December 31,	Nine Months Ended September 30,	Year Ended December 31,	
	2006	2006	2005	2004
	(consolidated)	(combined)		
Cash flows from operating activities:				
Net income	$ 3,367	$ 16,574	$ 15,073	$ 8,431
Adjustments to reconcile net income to net cash lows provided by operating activities:				
Dry hole costs	—	354	530	440
Impairment of unproved oil and natural gas properties	—	90	2,041	1,415
Asset retirement obligations accretion expense	89	129	171	160
Depreciation, depletion and amortization	1,180	4,388	4,409	4,135
Amortization of deferred loan costs	22	—	—	—
Unrealized gain on mark-to-market derivatives	(906)	—	—	—
Gain on sale of other property	—	—	—	(130)
Provision (benefit) for deferred income taxes	—	(540)	(211)	1,850
Equity in (income) loss of affiliates, net of distributions	—	94	(243)	633
Changes in operating assets and liabilities:				
Accounts receivable	(2,278)	1,258	(544)	(3,874)
Income tax receivable	—	—	463	(463)
Accounts payable and accrued liabilities	1,536	(3,487)	2,706	1,775
Due to affiliates	—	(2,089)	2,966	2,054
Income taxes	—	2,993	1,171	—
Other, net	(147)	350	(553)	278
Net cash flows provided by operating activities	2,863	20,114	27,979	16,704
Cash flows from investing activities:				
Acquisition of oil and natural gas properties, net of cash acquired	(69,517)	—	(11,224)	(282)
Development of oil and natural gas properties	(1,171)	(6,911)	(5,627)	(5,410)
Acquisition of other property	—	—	(38)	(12)
Proceeds from sale of property	—	—	10	2,380
Investment in equity investee	—	(130)	(918)	(497)
Net cash flows used in investing activities	(70,688)	(7,041)	(17,797)	(3,821)
Cash flows from financing activities:				
Repayment of advances-related party	—	—	(1,136)	(10,091)
Repayment of borrowings	(10,350)	—	—	—
Debt borrowings	28,000	—	8,650	—
Proceeds from initial public offering	81,065	—	—	—
Offering costs	(4,448)	—	—	—
Distribution to the Predecessors	(24,134)	—	—	—
Deferred loan costs	(433)	—	—	—
Contributions by partners	—	16,000	2,029	—
Distributions to partners and dividends paid	—	(33,330)	(14,238)	(2,069)
Net cash flows provided by (used in) financing activities	69,700	(17,330)	(4,695)	(12,160)
Increase (decrease) in cash and cash equivalents	1,875	(4,257)	5,487	723
Cash and cash equivalents – beginning of period	—	7,159	1,672	949
Cash and cash equivalents – end of period	$ 1,875	$ 2,902	$ 7,159	$ 1,672

See accompanying notes to consolidated/combined financial statements.

EV ENERGY PARTNERS, L.P.

STATEMENTS OF CHANGES IN OWNERS' EQUITY
(In thousands)

	Owners' Equity Excluding Accumulated Other Comprehensive Income (Loss)	Accumulated Other Comprehensive Income (Loss)	Total Owners' Equity
Predecessor *(Combined)*:			
Balance, January 1, 2004	$ 34,756	$ —	$ 34,756
Comprehensive income:			
Net income	8,431	—	
Unrealized loss on derivatives	—	(1,876)	
Reclassification adjustment into earnings	—	1,776	
Total comprehensive income			8,331
Contributions	198	—	198
Distributions	(2,069)	—	(2,069)
Balance, December 31, 2004	41,316	(100)	41,216
Comprehensive income:			
Net income	15,073	—	
Unrealized loss on derivatives	—	(8,391)	
Reclassification adjustment into earnings	—	4,223	
Total comprehensive income			10,905
Contributions	3,029	—	3,029
Distributions	(5,186)	—	(5,186)
Dividends	(9,054)	—	(9,054)
Balance, December 31, 2005	45,178	(4,268)	40,910
Comprehensive income:			
Net income	16,574	—	
Unrealized gain on derivatives	—	14,347	
Reclassification adjustment into earnings	—	(408)	
Total comprehensive income			30,513
Contributions	19,315	—	19,315
Distributions	(14,871)	—	(14,871)
Dividends	(12,627)	—	(12,627)
Balance, September 30, 2006	$ 53,569	$ 9,671	$ 63,240

See accompanying notes to consolidated/combined financial statements.

EV ENERGY PARTNERS, L.P.

STATEMENTS OF CHANGES IN OWNERS' EQUITY (continued)
(In thousands)

	Common Unitholders	Subordinated Unitholders	General Partner Interest	Accumulated Other Comprehensive Income	Total Owners' Equity
Successor *(Consolidated)*:					
Balance at September 30, 2006	$ —	$ —	$ —	$ —	$ —
Proceeds from initial public offering, net of underwriter discount	81,065	—	—	—	81,065
Offering costs	(4,448)	—	—	—	(4,448)
Acquisition of the Predecessors	9,919	22,829	3,312	5,392	41,452
Distribution to the Predecessors	(10,788)	(13,346)	—	—	(24,134)
Comprehensive income:					
Net income	1,953	1,347	67	—	
Reclassification adjustment into earnings	—	—	—	(1,049)	
Total comprehensive income					2,318
Balance, December 31, 2006	$ 77,701	$ 10,830	$ 3,379	$ 4,343	$ 96,253

See accompanying notes to consolidated/combined financial statements.

Note 1. Organization and Nature of Business

EV Energy Partners, L.P. (the "Partnership") is a publicly held limited partnership that engages in the acquisition, development and production of oil and natural gas properties. The Partnership consummated the acquisition of its predecessors and an initial public offering of its common units effective October 1, 2006. The Partnership's general partner is EV Energy GP, L.P., a Delaware limited partnership, and the general partner of its general partner is EV Management, LLC ("EV Management"), a Delaware limited liability company.

The Partnership's predecessors (the "Predecessors") were:

- EV Properties, L.P. ("EV Properties"), a limited partnership that owns oil and natural gas properties and related assets in the Monroe field in Northern Louisiana and in the Appalachian Basin in West Virginia, and
- CGAS Exploration, Inc. ("CGAS Exploration"), a corporation that owns oil and natural gas properties and related assets in the Appalachian Basin in Ohio.

EV Properties was formed on April 12, 2006 by EnerVest Management Partners, Ltd. ("EnerVest") and investment funds affiliated with EnCap Investments, L.P. ("EnCap") to acquire the business of the following partnerships which were controlled by EnerVest:

- EnerVest Production Partners, Ltd. ("EnerVest Production Partners"), which owned oil and natural gas properties and related assets in the Monroe field in Northern Louisiana, and
- EnerVest WV, L.P. ("EnerVest WV"), which owned oil and natural gas properties and related assets in West Virginia.

In May 2006, EnerVest and its subsidiaries contributed all of the general and limited partnership interests in EnerVest Production Partners and the general partnership interest in EnerVest WV to EV Properties in exchange for general and limited partnership interests in EV Properties. In addition, EnCap contributed $16.0 million in cash to EV Properties in exchange for limited partnership interests in EV Properties, which then used the $16.0 million contribution from the EnCap investment funds to purchase the limited partnership interests in EnerVest WV. As a result of these transactions, EnerVest and EnCap owned EV Properties and EV Properties owned all of the interests in the partnerships that owned the oil and natural gas properties and related assets in West Virginia and Louisiana. In addition, EV Investors, a partnership formed by the management of EV Management, was admitted as a limited partner of EV Properties.

Note 2. Summary of Significant Accounting Policies

Basis of Presentation

The consolidated financial statements include the operations of the Partnership and all of its subsidiaries ("we," "our" or "us") from October 1, 2006 through December 31, 2006. The combined financial statements of the Predecessors reflect the operations of the following entities:

- the combined operations of EnerVest Production Partners, EnerVest WV and CGAS Exploration for periods before May 12, 2006, and
- the combined operations of EV Properties and CGAS Exploration from May 12, 2006 through September 30, 2006.

All significant intercompany accounts and transactions have been eliminated in consolidation/combination. In the Notes to Consolidated/Combined Financial Statements, all dollar and share amounts in tabulations are in thousands of dollars and shares, respectively, unless otherwise indicated.

Note 2. Summary of Significant Accounting Policies – (continued)

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/combined 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.

Accounts Receivable

Accounts receivable from oil and natural gas 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, 2006 and 2005, 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 credit exposure related to our customers.

Property and Depreciation

Our oil and natural gas producing activities are accounted for under the successful efforts method of accounting. Under this method, exploration costs, other than the costs of drilling exploratory wells, are charged to expense as incurred. Costs that are associated with the drilling of successful exploration wells are capitalized if proved reserves are found. Lease acquisition costs are capitalized when incurred. Capitalized costs associated with unproved properties totaled $0.2 million and $5.3 million as of December 31, 2006 and December 31, 2005, 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.

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 net proved oil and natural gas reserves as estimated by independent petroleum engineers. Proved developed reserves are used in computing unit rates for drilling and development costs and total proved reserves are used for depletion rates of leasehold, platform, and pipeline costs.

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

Impairment of Long-Lived Assets

We evaluate our proved oil and natural gas properties and related equipment and facilities for impairment whenever events or changes in circumstances indicate that the carrying amounts of such properties may not be recoverable. The determination of recoverability is made based upon estimated undiscounted future net cash flows.

Note 2. Summary of Significant Accounting Policies – (continued)

The amount of impairment loss, if any, is determined by comparing the fair value, as determined by a discounted cash flow analysis, with the carrying value of the related asset. For the years ended December 31, 2006, 2005 and 2004, we recorded no impairments related to our proved oil and natural gas properties.

Unproved oil and natural gas properties are assessed periodically on a property-by-property basis, and any impairment in value is recognized. For the nine months ended September 30, 2006 and for the years ended December 31, 2005 and 2004, our predecessors recorded $0.1 million, $2.0 million and $1.4 million, respectively, of impairments related to our unproved oil and natural gas properties. We recorded no impairments related to our unproved oil and natural gas properties for the three months ended December 31, 2006.

Asset Retirement Obligations

We account for our legal obligations associated with retirement of long-lived assets in accordance with Statement of Financial Accounting Standards (“SFAS”) No. 143, *Accounting for Asset Retirement Obligations.* SFAS No. 143 requires that the fair value of a liability associated with an asset retirement obligation (“ARO”) be recognized in the period in which it is incurred if a reasonable estimate can be made. The associated retirement costs are capitalized as part of the carrying amount of the long-lived asset and subsequently depreciated over the estimated useful life of the asset. The liability is eventually extinguished when the asset is taken out of service.

Revenue Recognition

Oil and natural gas revenues are recognized when production is sold to a purchaser at fixed or determinable prices, when delivery has occurred and title has transferred and collectibility of the revenue is probable. 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 material gas imbalances at December 31, 2006 or 2005.

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.

One of the Predecessors was a corporation subject to federal and state income taxes. They used the liability method for determining their income taxes, under which current and deferred tax liabilities and assets are recorded in accordance with enacted tax laws and rates. Under this method, the amounts of deferred tax liabilities and assets at the end of each period are determined using the tax rate expected to be in effect when taxes are actually paid or recovered. Future tax benefits are recognized to the extent that realization of such benefits is more likely than not. Deferred income taxes are provided for the estimated income tax effect of temporary difference between financial and tax bases in assets and liabilities. Deferred tax assets are also provided for certain tax credit carryforwards. A valuation allowance to reduce deferred tax is established when it is more likely than not that some portion of all of the deferred tax assets will not be realized.

Net Income per Limited Partner Unit

We calculate net income per limited partner unit in accordance with Emerging Issues Task Force 03-06, *Participating Securities and the Two-Class Method under FASB Statement No. 128* (“EITF 03-06”). EITF 03-06 requires that in any accounting period where our aggregate net income exceeds our aggregate distribution for such period, we are required to present earnings per unit as if all of the earnings for the periods were distributed, regardless of whether those earnings would actually be distributed during a particular period from an economic or practical perspective.

Note 2. Summary of Significant Accounting Policies – (continued)

Fair Value of Financial Instruments

Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, long-term debt and derivative financial instruments. Commodity derivatives are recorded at fair value. The carrying amount of our other financial instruments other than debt approximates fair value because of the short-term nature of the items. The carrying value of our debt approximates fair value because our debt has variable interest rates.

Derivative Financial Instruments

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

The Predecessors accounted for their derivative financial instruments as cash flows hedges in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities, as amended.* Derivative financial instruments that had been designated and qualified as cash flows hedging instruments were reported at fair value. The change in fair value of the derivative financial instrument was initially reported as a component of other comprehensive income ("OCI"). Amounts in OCI were reclassified into net income (as a component of revenues) in the same period in which the hedged forecasted transaction affected earnings. In the event that a forecasted transaction is no longer probable of occurrence, the amount deferred in OCI for such forecasted transaction would be reclassified into net income.

As of October 1, 2006, we elected not to designate any of our derivative financial instruments as hedging instruments as defined by SFAS No. 133. The amount in OCI at that date related to derivatives that previously were designated and accounted for as cash flow hedges continues to be deferred until the underlying production is produced and sold, at which time the amounts are reclassified from OCI and reflected as a component of revenues. Changes in the fair value of derivatives that existed at October 1, 2006 and any derivatives entered thereafter are no longer deferred in OCI, but rather are recorded immediately to net income as "Gain on mark-to-market derivatives, net" in our consolidated statement of operations.

Business Segment Reporting

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

New Accounting Standards

In February 2006, the Financial Accounting Standards Board ("FASB") issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments,* to simplify and make more consistent the accounting for certain financial instruments. SFAS No. 155 amends SFAS No. 133 to permit fair value remeasurement for any hybrid financial instrument with an embedded derivative that would otherwise require bifurcation, provided that the whole instrument is accounted for on a fair value basis. SFAS No. 155 also amends SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities,* to allow a qualifying special purpose entity to hold a derivative financial instrument that pertains to a beneficial interest other than another derivative financial instrument. SFAS No. 155 is effective for all financial instruments acquired or issued after the beginning of an entity's first fiscal year that begins after September 15, 2006. We adopted SFAS No. 155 on January 1, 2007, and there was no impact on our consolidated financial statements.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements,* to provide guidance for using fair value to measure assets and liabilities. SFAS No. 157 establishes a fair value hierarchy and clarifies the

Note 2. Summary of Significant Accounting Policies – (continued)

principle that fair value should be based on assumptions market participants would use when pricing the asset or liability. SFAS No. 157 also requires expanded disclosure of the effect on earnings for items measured using unobservable data. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. We will adopt SFAS No. 157 on January 1, 2008 and do not expect the adoption to have a material impact on our consolidated financial statements.

In September 2006, the Securities and Exchange Commission (the "SEC") issued Staff Accounting Bulletin No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements* ("SAB 108"). SAB 108 addresses how the effects of prior year uncorrected misstatements should be considered when quantifying misstatements in current year financial statements. SAB 108 requires companies to quantify misstatements using a balance sheet and income statement approach and to evaluate whether either approach results in quantifying an error that is material in light of relevant quantitative and qualitative factors. SAB 108 is effective for periods ending after November 15, 2006. We adopted SAB 108 on December 31, 2006, and there was no impact on our consolidated financial statements.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115*. SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. Unrealized gains and losses on items for which the fair value option has been selected are reported in earnings. SFAS No. 159 also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. We will adopt SFAS No. 159 on January 1, 2008, and we have not yet determined the impact, if any, on our consolidated financial statements.

Reclassifications

Certain reclassifications have been made to the prior year's combined financial statements to conform with the current period presentation.

Note 3. Initial Public Offering

On September 29, 2006, we closed the initial public offering of 3.9 million of our common units at a price of $20.00 per common unit, and on October 26, 2006, we closed the sale of an additional 0.4 million common units at a price per unit of $20.00 pursuant to the exercise of the underwriters' over-allotment option. Net proceeds from the sale of the common units were approximately $76.6 million. The common units sold in our initial public offering represented a 57.1% limited partnership interest. Our common units began trading on the NASDAQ Global Market under the symbol "EVEP." For financial reporting purposes, the effective date of the closing of our initial public offering was October 1, 2006.

At the closing of our initial public offering, the partners of EV Properties contributed a portion of their general and limited partnership interests in EV Properties to us in exchange for limited partnership interests in our general partner. Our general partner contributed the interests it received in EV Properties to us in exchange for a 2% general partnership interest and incentive distribution rights representing limited partnership interests. The limited partners of EV Properties also contributed the remainder of their interests in EV Properties to us in exchange for common units representing limited partnership interests, subordinated units representing limited partnership interests and cash payments totaling $28.1 million. Since these transactions were between entities under common control, we did not apply purchase accounting, and we carried over the historical cost basis of EV Properties.

In addition, at the closing of our initial public offering, CGAS Exploration formed a limited partnership and contributed a portion of its producing properties and related assets to the partnership in exchange for a limited partnership interest. CGAS Exploration then contributed this limited partnership interest to us in exchange for common units, subordinated units and a cash payment of $38.3 million. Since EnerVest owned 25.75% of CGAS Exploration, the historical cost basis of 25.75% of the producing properties and related assets contributed by CGAS Exploration was carried over. Purchase accounting was applied to the remaining 74.25%.

Note 3. Initial Public Offering – (continued)

Immediately following our initial public offering, we had outstanding a 2% general partnership interest and the incentive distribution rights and common units and subordinated units owned by the public (common units), and the former partners of EV Properties (common units and subordinated units) and CGAS Exploration (common units and subordinated units).

Additionally, we entered into an Omnibus Agreement with EnerVest that governs our relationship with EnerVest and its affiliates regarding the following matters:

- our obligation to reimburse EnerVest for payment of operating expenses it incurs on our behalf;
- our obligation to pay EnerVest a monthly administrative fee for providing us general and administrative services with respect to our business and operations;
- our obligation to reimburse EnerVest for insurance coverage expenses it incurs with respect to our operations;
- EnerVest’s obligation to provide us with general and administrative services equivalent to what it provided the Predecessors; and
- EnerVest’s obligation to indemnify us for certain liabilities and our obligation to indemnify EnerVest for certain liabilities.

We also entered into the following transactions and executed the following agreements:

- we entered into a new five-year $150.0 million senior secured revolving credit agreement;
- we used a portion of the proceeds from the sale of common units to repay $10.4 million of outstanding indebtedness we assumed in connection with the acquisition of the Predecessors;
- our long-term incentive plan became effective for employees, consultants and directors of EV Management and employees and consultants of its affiliates who perform services for us and our affiliates;
- our subsidiaries entered into a contract operating agreement with a subsidiary of EnerVest under which the subsidiary acts as contract operator of the oil and natural gas wells and related gathering systems and production facilities; and
- EV Management entered into employment agreements with Michael Mercer to act as our senior vice president and chief financial officer and with Kathryn MacAskie to act as our senior vice president of acquisitions and divestitures.

Note 4. Acquisitions

In December 2006, we acquired oil and natural gas properties in the Mid-Continent area in Oklahoma, Texas and Louisiana for $27.6 million. The acquisition was financed with borrowings under our credit facility.

The fair value of the assets acquired and liabilities assumed at the date of acquisition was as follows:

Accounts receivable – oil and natural gas sales	$ 1,620
Oil and natural gas properties	26,626
Accounts payable and accrued liabilities	(194)
Asset retirement obligations	(473)
Net cash consideration	$ 27,579

Note 4. Acquisitions – (continued)

The following table reflects pro forma revenues, net income and net income per limited partner unit as if this acquisition had taken place at the beginning of the periods presented. These unaudited pro form amounts do not purport to be indicative of the results that would have actually been obtained during the periods presented or that may be obtained in the future.

	Successor	Predecessor	
	Three Months Ended December 31,	Nine Months Ended December 31,	Year Ended December 31,
Revenues	$ 9,776	$ 47,490	$ 46,274
Net income	4,026	18,944	19,647
Net income per limited partner unit:			
Basic	$ 0.52	—	—
Diluted	$ 0.52	—	—

In March 2005, one of the Predecessors acquired interests in oil and natural gas properties in the Monroe Field in Louisiana for $10.7 million. The acquisition was financed with borrowings under their credit facility. The purchase price was allocated based on the fair value of the assets acquired and liabilities assumed. Pro forma results of operations have not been presented because the effects of this acquisition were not material to the combined financial statements of the Predecessors.

Note 5. Risk Management

Our business activities expose us to risks associated with changes in the market price of oil and natural gas. As such, future earnings are subject to change due to changes in these market prices. We use derivative instruments to reduce our risk of changes in the prices of oil and natural gas. As of December 31, 2006, we had entered into swap agreements and costless collars for oil and natural gas with the following terms:

Period Covered	Index	Hedged Volume per Day (Bbl or MMBtu)	Weighted Average Fixed Price	Weighted Average Floor Price	Weighted Average Ceiling Price
Oil:					
Costless Collar – 2008	WTI	125	$	$ 62.000	$ 73.950
Costless Collar – 2009	WTI	125		62.000	73.900
Swap – 2007	WTI	125	66.300		
Swap – 2007	WTI	125	76.400		
Natural Gas:					
Costless Collar – 2008		1,000		7.500	9.850
Costless Collar – 2009		1,000		7.500	8.800
Swap – 2007	Dominion Appalachia	3,100	10.265		
Swap – 2008	Dominion Appalachia	2,700	9.750		
Swap – 2007	NYMEX	1,500	9.820		
Swap – 2007	NYMEX	500	10.000		
Swap – 2008	NYMEX	1,500	9.360		
Swap – 2008	NYMEX	500	9.500		

At December 31, 2006, the fair value associated with the derivative instruments is an asset of $8.2 million.

The Predecessors accounted for their derivative instruments as cash flows hedges in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities, as amended.* Derivative instruments that had

Note 5. Risk Management – (continued)

been designated and qualified as cash flows hedging instruments were reported at fair value. The change in fair value of the derivative instruments was initially reported as a component of other comprehensive income (“OCI”). Amounts in OCI were reclassified into net income in the same period in which the hedged forecasted transaction affected earnings.

As of October 1, 2006, we elected not to designate any of our derivative instruments as hedging instruments as defined by SFAS No. 133. The amount in OCI at that date related to derivatives that previously were designated and accounted for as cash flow hedges continues to be deferred until the underlying production is produced and sold, at which time the amounts are reclassified from OCI and reflected as a component of revenue.

As of December 31, 2006, we had OCI of $4.3 million related to derivative instruments where we removed the hedge designation. During the three months ended December 31, 2006, we reclassified $1.0 million from OCI to “Gain (loss) on derivatives, net,” and we anticipate that $2.8 million will be reclassified from OCI during the year ended December 31, 2007.

As a result of our election not to designate our derivatives as hedges for accounting purposes, changes in the fair value of the derivatives that existed at October 1, 2006 and any derivatives entered into thereafter are not deferred in OCI, but rather are recorded immediately to net income as “Gain on mark-to-market derivatives, net” in our consolidated statement of operations. During the three months ended December 31, 2006, we recorded a $0.1 million loss on the change in fair value of the swap agreements and costless collars in “Gain on mark-to-market derivatives.”

Note 6. 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.

One of the Predecessors was a corporate entity which was subject to federal and state taxation. The provision for income taxes is comprised of the following:

	Nine Months Ended September 30, 2006	Year Ended December 31, 2005	Year Ended December 31, 2004
Current	$ 6,349	$ 5,560	$ 671
Deferred	(540)	(211)	1,850
Provision for income taxes	$ 5,809	$ 5,349	$ 2,521

The provision for income taxes differs from the amount computed by applying the U.S. statutory income tax rate to income before income taxes and equity in income (loss) of affiliates for the reasons set forth below:

	Nine Months Ended September 30, 2006	Year Ended December 31, 2005	Year Ended December 31, 2004
Income before income taxes and equity in income (loss) of affiliates	$ 22,219	$ 19,857	$ 11,573
Less: Income not subject to income taxes	(3,862)	(4,582)	(2,366)
Income before income taxes and equity in income (loss) of affiliates subject to income taxes	18,357	15,275	9,207
Statutory rate	35%	34%	34%
Income tax expense at statutory rate	6,425	5,193	3,130
Reconciling items:			
State income taxes, net of federal benefit	656	678	—
Percentage depletion in excess of basis	(1,225)	(448)	(609)
Other permanent items	(47)	(74)	—
Provision for income taxes	$ 5,809	$ 5,349	$ 2,521

Note 6. Income Taxes – (continued)

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes, as well as operating loss and tax credit carryforwards. The tax effects of the Predecessor's temporary differences and carryforwards are as follows:

	December 31, 2005
Deferred tax assets:	
Net operating loss carryforward	$ 155
Derivative instruments	1,871
Total	2,026
Deferred tax liabilities:	
Oil, natural gas and other properties	(4,356)
Net deferred tax liability	$ (2,330)
Reflected in the accompanying balance sheet as:	
Current deferred income taxes	$ 1,875
Deferred income taxes	(4,205)
	$ (2,330)

At December 31, 2005, the Predecessor had a net operating loss carryforward of $0.5 million that began to expire in 2006.

Note 7. Asset Retirement Obligations

If a reasonable estimate of the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon wells can be made, 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. 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. The changes in the aggregate asset retirement obligations are as follows:

Predecessor:	
Balance as of December 31, 2004	$ 2,050
Liabilities incurred	502
Accretion expense	171
Revisions in estimated cash flows	29
Balance as of December 31, 2005	2,752
Liabilities incurred	11
Accretion expense	129
Sale of assets	(60)
Balance as of September 30, 2006	$ 2,832
Successor:	
Balance as of September 30, 2006	$ —
Liabilities incurred or assumed in acquisitions	4,387
Accretion expense	89
Revisions in estimated cash flows	712
Balance as of December 31, 2006	$ 5,188

Note 8. Long-Term Debt

As of December 31, 2006, our credit facility consists of a $150.0 million senior secured revolving credit facility that expires in September 2011. Borrowings under the facility are secured by a first priority lien on substantially all of our assets and the assets of our subsidiaries. We may use borrowings under the facility for acquiring and

Note 8. Long-Term Debt – (continued)

developing oil and natural gas properties, for working capital purposes, for general corporate purposes and, so long as outstanding borrowings are less than 90% of the borrowing base, for funding distributions to partners. We also may use up to $20.0 million of available borrowing capacity for letters of credit. The facility contains certain covenants which, among other things, require the maintenance of a current ratio (as defined in the facility) of greater than 1.00 and a ratio of total debt to earnings plus interest expense, taxes, depreciation, depletion and amortization expense and exploration expense of no greater than 4.0 to 1.0. As of December 31, 2006, we were in compliance with all of the facility covenants.

Borrowings under the facility bear interest at a floating rate based on, at our election, a base rate or the London Inter-Bank Offered Rate plus applicable premiums based on the percent of the borrowing base that we have outstanding (6.98% at December 31, 2006). As of December 31, 2006, the amount of borrowings that we may have outstanding under the facility is $50.0 million and is subject to a borrowing base which is calculated semi-annually and in connection with material acquisitions or divestitures of properties. At December 31, 2006, we had $28.0 million outstanding under the facility.

As of December 31, 2005, the Predecessors' credit facility consisted of a $15.0 million reducing revolving line of credit that expired in January 2008. EnerVest and EnerVest Production Partners were parties to the line of credit. Borrowings under the line of credit were secured by substantially all of the assets owned by EnerVest Production Partners. Borrowings under the line of credit bore interest at a rate equal to the Compass Bank Index Rate (5.77% at December 31, 2005). At December 31, 2005, we had $10.5 million outstanding under the line of credit. The line of credit was repaid with proceeds from our initial public offering.

Note 9. Commitments and Contingencies

Litigation

We are involved in disputes or legal actions arising in the ordinary course of business. We do not believe the outcome of such disputes or legal actions will have a material adverse effect on our consolidated financial statements.

Environmental Matters

Our past and present operations include activities which are subject to extensive domestic (including U.S. federal, state and local) environmental regulations with regard to air and water quality and other environmental matters. Our environmental procedures, policies and practices are designed to ensure compliance with existing laws and regulations and to minimize the possibility of significant environmental damage.

We expense environmental costs if they relate to an existing condition caused by past operations and do not contribute to current or future revenue generation. Liabilities are recorded when site restoration and environmental remediation and cleanup obligations are either known or considered probable and can be reasonably estimated. Recoveries of environmental costs through insurance, indemnification arrangements or other sources are included in other assets to the extent such recoveries are considered probable. Neither we nor the Predecessors incurred material environmental expenses during the years ended December 31, 2006, 2005 and 2004.

Note 10. Owners' Equity

Issuance of Units

On September 29, 2006, we closed our initial public offering of 3.9 million of our common units, and on October 26, 2006, we closed the sale of an additional 0.4 million common units pursuant to the exercise of the underwriters' over-allotment option. Upon the closing of our initial public offering (and taking into account the underwriters' exercise of their over-allotment option), EnerVest and its affiliates received an aggregate of 136,304 common units and 2,663,830 subordinated units.

Note 10. Owners' Equity – (continued)

Units Outstanding

At December 31, 2006, owner's equity consists of 4,495,000 common units outstanding (including 185,400 common units held by affiliates of EV Management, including directors and executive officers), 3,100,000 subordinated units (held by affiliates of EV Management, including directors and executive officers), collectively representing a 98% limited partnership interest in us, and a 2% general partnership interest.

Common Units

During the subordination period, the common units will have the right to receive distributions of available cash from operating surplus each quarter in an amount equal to $0.40 per common unit plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. The purpose of the subordinated units is to increase the likelihood that during the subordination period there will be available cash to be distributed on the common units.

The subordination period will extend until the first day of any quarter beginning after September 30, 2011 that each of the following tests are met:

- distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equaled or exceeded the minimum quarterly distribution for each of the three consecutive, non-overlapping four quarter periods immediately preceding that date;
- the "adjusted operating surplus" (as defined in our partnership agreement) generated during each of the three consecutive, non-overlapping four quarter periods immediately preceding that date equaled or exceeded the sum of the minimum quarterly distributions on all of the outstanding common and subordinated units during those periods on a fully diluted basis during those periods; and
- there are no arrearages in payment of the minimum quarterly distribution on the common units.

If the unitholders remove our general partner other than for cause and units held by the general partner and its affiliates are not voted in favor of such removal:

- the subordination period will end and each subordinated unit will immediately convert into one common unit;
- any existing arrearages in payment of the minimum quarterly distribution on the common units will be extinguished; and
- the general partner will have the right to convert its 2% general partner interest and its incentive distribution rights into common units or to receive cash in exchange for those interests.

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.

Subordinated Units

During the subordination period, the subordinated units have no right to receive distributions of available cash from operating surplus until the common units receive distributions of available cash from operating surplus in an amount equal to the minimum quarterly distribution of $0.40 per quarter, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters. No arrearages will be paid to subordinated units.

Note 10. Owners' Equity – (continued)

The subordinated units may convert to common units on a one-for-one basis when certain conditions as set forth in our partnership agreement are met. Our partnership agreement also sets forth the calculation to be used to determine the amount and priority of cash distributions that the common unitholders, subordinated unitholders and our general partner will receive.

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

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, subordinated unitholders and general partner will receive.

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

Allocations of Net Income

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

Cash Distributions

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

Within 45 days after the end of each quarter, we will distribute all of our available cash (as defined in our partnership agreement) to our general partner and unitholders of record on the applicable record date. The amount of available cash generally is all cash on hand at the end of the quarter; less the amount of cash reserves established by our general partner to provide for the proper conduct of our business, to comply with applicable law, 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 for any quarter during the subordination period 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;
- *second*, 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 any arrearages in payment of the minimum quarterly distribution on the common units for any prior quarters during the subordination period;

Note 10. Owners' Equity – (continued)

- *third*, 98% to the subordinated unitholders, pro rata, and 2% to the general partner, until we distribute for each subordinated 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	$0.40	98%	2%
First target distribution	Up to $0.46	98%	2%
Second target distribution	Above $0.46, up to $0.50	85%	15%
Thereafter	Above $0.50	75%	25%

On January 26, 2007, the board of directors of EV Management declared a $0.40 per unit distribution on all common and subordinated units for the fourth quarter of 2006. On February 14, 2007, the fourth quarter 2006 distribution was paid. The aggregate amount of the distribution was $3.1 million.

Note 11. Net Income Per Limited Partner Unit

The computation of net income per limited partner unit is based on the weighted average number of common and subordinated units outstanding during the year. Basic and diluted net income per limited partner unit is determined by dividing net income, after deducting the amount allocated to the general partner interest (including its incentive distribution in excess of its 2% interest), by the weighted average number of outstanding limited partner units during the period in accordance with EITF 03-06.

The following sets forth the net income allocation using this method:

	Successor October 1, 2006 through December 31, 2006	
	$	Per Limited Partner Unit
Net income	$ 3,367	
Less: General partner's 2% interest in net income	(67)	
Net income available for limited partners	$ 3,300	$ 0.43

We did not declare a cash distribution during the period October 1, 2006 through December 31, 2006 which would result in an incentive distribution to the general partner as indicated above.

Note 12. Employee Benefit Plan With Related Party

In September 2006, the board of directors of EV Management adopted 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 allows for the award of unit options, phantom units, restricted units and deferred equity rights, and the aggregate amount of our common units that may be awarded under the plan is 775,000 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 or the board of directors administers the Plan. As of December 31, 2006, no awards of any kind had been granted under the Plan.

Note 13. Related Party Transactions

Successor

Pursuant to the Omnibus Agreement, we paid EnerVest $0.3 million in the three months ended December 31, 2006 in monthly administrative fees for providing us general and administrative services. These fees are included in general and administrative expenses in our consolidated statement of operations.

We have entered into operating agreements with EnerVest whereby a subsidiary of EnerVest acts as contract operator of the oil and natural gas wells and related gathering systems and production facilities in which we own an interest. During the three months ended December 31, 2006, we reimbursed EnerVest approximately $0.6 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. These costs are included in lease operating expenses in our consolidated statement of operations. Additionally, in its role as contract operator, this EnerVest subsidiary also collects proceeds from oil and natural gas sales and distributes them to us and other working interest owners. We believe that the aforementioned services were provided to us at fair and reasonable rates relative to the prevailing market.

During the three months ended December 31, 2006, we sold $1.3 million of natural gas to EnerVest Monroe Marketing, Ltd. (“EnerVest Monroe Marketing”), a subsidiary of one of the EnerVest partnerships. The purchase price was spot market price based on the average of two index prices for natural gas production in the area, less a gathering fee of either $0.10 per Mcf or $0.75 per Mcf depending upon whether compression and additional gathering services or facilities are provided. EnerVest Monroe Marketing resold the natural gas and realized a profit of $0.1 million on the resale of our natural gas production.

Predecessor

Pursuant to terms of certain agreements, the Predecessors paid $42,000, $0.1 million and $0.1 million to EnerVest and its subsidiaries for management, accounting and advisory services in the nine months ended September 30, 2006 and the years ended December 31, 2005 and 2004, respectively. In addition, a subsidiary of EnerVest served as operator of the Predecessors’ properties and received reimbursement through Council of Petroleum Accountants Societies (“COPAS”) overhead billings. The Predecessors paid this EnerVest subsidiary $1.0 million, $1.2 million and $1.2 million in the nine months ended September 30, 2006 and the years ended December 31, 2005 and 2004, respectively, and these amounts are reflected in lease operating expenses within the combined statements of operations. Additionally, in its role as operator, this EnerVest subsidiary also collected proceeds from oil and natural gas sales and distributed them to the Predecessor and other working interest owners. We believe that the aforementioned services were provided to the Predecessors and their affiliates at fair and reasonable rates relative to the prevailing market.

During the nine months ended September 30, 2006 and the years ended December 31, 2005 and 2004, the Predecessors sold $4.3 million, $6.0 million and $0.5 million, respectively, of natural gas to EnerVest Monroe Marketing. The purchase price was spot market price based on the average of two index prices for natural gas production in the area, less a gathering fee of either $0.10 per Mcf or $0.75 per Mcf depending upon whether compression and additional gathering services or facilities were provided. EnerVest Monroe Marketing resold the natural gas and realized a profit of $0.3 million and $0.1 million in the nine months ended September 30, 2006 and the year ended December 31, 2005, respectively. No profit was recognized in the year ended December 31, 2004.

In connection with the formation of EV Properties in the second quarter of 2006, EnerVest Production Partners and EnerVest WV sold certain non-material assets not used in their oil and natural gas activities. These transactions are described below:

- The Predecessors sold oil and natural gas properties totaling $0.4 million to a wholly owned subsidiary of EnerVest. No loss was recognized on the sale as the transaction was deemed to be a transfer of assets between entities under common control;

Note 13. Related Party Transactions – (continued)

- The Predecessors sold other property totaling $0.2 million to a wholly owned subsidiary of EnerVest. No loss was recognized on the sale as the transaction was deemed to be a distribution to the general partner; and
- The Predecessors sold investments in affiliated companies totaling $1.3 million to a wholly owned subsidiary of EnerVest. No loss was recognized on the sale as the transaction was deemed to be a transfer of assets between entities under common control. Prior to the sale, the Predecessors recorded the proportionate share of net income from the investments in affiliated companies under the equity method of accounting.

In addition, in connection with the contribution of the general partner and limited partner interests in EnerVest Production Partners to EV Properties, accounts payable of $3.2 million was forgiven by EnerVest and converted to owners' equity.

Note 14. Other Supplemental Information

Supplemental cash flows and non-cash transactions were as follows:

	Successor	Predecessor		
	Three Months Ended December 31, 2006	Nine Months Ended September 30, 2006	Year Ended December 31, 2005	Year Ended December 31, 2004
Supplemental cash flows information:				
Cash paid for interest	$ 16	$ 686	$ 569	$ 291
Cash paid for income taxes	—	3,357	3,921	1,135
Non-cash transactions:				
Issuance of common and subordinated units in conjunction with the acquisition of the Predecessors	36,060	—	—	—
Costs for development of oil and natural gas properties in accounts payable and accrued liabilities	557	241	—	—
Increase in oil and natural gas properties from purchase of limited partnership interest in EnerVest WV	—	7,681	—	—
Distribution/sale of property and investments in affiliates to EnerVest	—	1,849	—	—
Reduction in debt through partner contribution	—	150	1,000	200
Increase in due to affiliates for the incurrence of offering costs on our behalf	—	4,000	—	—
Conversion of accounts payable to EnerVest to owners' equity	—	3,165	—	—

Note 15. Quarterly Data (Unaudited)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	Predecessor			Successor
2006				
Revenues	$ 13,158	$ 13,053	$ 13,880	$ 7,818
Gross profit(1)	9,749	9,772	10,440	5,063
Net income	6,222	4,851	5,501	3,367
Limited partners' interest in net income(2)	—	—	—	3,300
Net income per limited partner unit(2)				
Basic				$ 0.43
Diluted				$ 0.43
	Predecessor			
2005				
Revenues	$ 9,809	$ 10,484	$ 11,102	$ 12,784
Gross profit(1)	7,475	7,412	7,634	8,470
Net income	3,922	2,937	4,191	4,023

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

(2) Calculated for the period beginning with our initial public offering effective October 1, 2006.

Note 16. Supplementary Information on Oil and Natural Gas Activities

The following disclosures of costs incurred related to oil and natural gas activities are presented in accordance with SFAS No. 69, Disclosure about Oil and Gas Producing Activities:

	Successor	Predecessor		
	Three Months Ended December 31, 2006	Nine Months Ended September 30, 2006	Year Ended December 31, 2005	Year Ended December 31, 2004
Costs incurred in oil and natural gas producing activities:				
Acquisition of proved properties	$ 112,952	$ —	$ 10,778	$ —
Acquisition of unproved properties	173	—	445	282
Development of oil and natural gas properties	1,728	7,152	5,097	4,970
Exploration costs	—	1,415	3,069	1,721
Asset retirement costs incurred and revised	712	11	532	(442)
Total	$ 115,565	$ 8,578	$ 19,921	$ 6,531

	Successor December 31, 2006 (consolidated)	Predecessor December 31, 2005 (combined)
Capitalized costs related to oil and natural gas producing activities:		
Evaluated properties:		
Proved properties	$ 118,320	$ 65,245
Unproved properties	173	1,498
Accumulated depreciation, depletion and amortization	(4,092)	(9,706)
Net capitalized costs	$ 114,401	$ 57,037

Note 17. Estimated Proved Oil and Natural Gas Reserves (Unaudited)

Our estimated proved developed and estimated proved undeveloped 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 and natural gas reserves may not occur in the periods assumed, and actual prices realized and actual costs incurred may vary significantly from those used in this estimate. Proved reserves represent estimated quantities of oil, natural gas and condensate that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimates were made. Estimated proved developed reserves are estimated proved reserves expected to be recovered through wells and equipment in place and under operating methods in use at the time the estimates were made. The estimates of proved reserves for us as of December 31, 2006 and for CGAS Exploration and EnerVest WV as of December 31, 2005 and 2004 have been prepared by Cawley, Gillespie, & Associates, Inc., independent petroleum consultants. The estimates of proved reserves for EnerVest Production Partners as of December 31, 2005 have been materially prepared by Cawley, Gillespie, & Associates, Inc. The estimated proved reserve information for EnerVest Production Partners as of December 31, 2004 is based on EnerVest's internal engineering estimates.

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)	MMcfe(3)
Predecessor:			
Proved reserves:			
Proved reserves, January 1, 2004	1,347	38,307	46,389
Revision of previous estimates	223	(810)	531
Production	(153)	(3,589)	(4,504)
Extensions and discoveries	67	1,844	2,244
Proved reserves, December 31, 2004	1,484	35,752	44,660
Purchase of minerals in place	—	9,816	9,816
Revision of previous estimates	156	2,308	3,243
Production	(174)	(3,901)	(4,947)
Extensions and discoveries	202	6,908	8,119
Proved reserves, December 31, 2005	1,668	50,883	60,891
Revision of previous estimates	(139)	(10,752)	(11,590)
Production	(147)	(3,275)	(4,157)
Extension and discoveries	47	1,157	1,440
Proved reserves, September 30, 2006	1,429	38,013	46,584
Proved developed reserves:			
December 31, 2004	1,479	35,198	44,069
December 31, 2005	1,553	45,821	55,136
September 30, 2006	1,376	35,947	44,203
Successor:			
Proved reserves:			
Proved reserves, September 30, 2006	—	—	—
Purchase of minerals in place	1,992	49,050	61,002
Revision of previous estimates	—	91	91
Production	(18)	(625)	(733)
Extensions and discoveries	46	875	1,151
Proved reserves, December 31, 2006	2,020	49,391	61,511
Proved developed reserves:			
December 31, 2006	1,920	45,906	57,425

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

Note 18. Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves (Unaudited)

The following tables, which present a standardized measure of discounted future net cash flows and changes therein relating to estimated proved oil and natural gas reserves, are presented pursuant to SFAS No. 69. In computing this data, assumptions other than those required by SFAS No. 69 could produce different results. Accordingly, the data should not be construed as representative of the fair market value of our estimated proved oil and natural gas reserves. The following assumptions have been made:

- Future revenues were based on year end oil and natural gas prices. Future price changes were included only to the extent provided by existing contractual agreements.
- Production and development costs were computed using year end costs assuming no change in present economic conditions.
- Future net cash flows were discounted at an annual rate of 10%.
- Future income taxes were computed only for CGAS Exploration using the approximate statutory tax rate and giving effect to available net operating losses, tax credits and statutory depletion. No future income taxes were computed for us, EnerVest WV or EnerVest Production Partners in accordance with their standing as non taxable entities.

The standardized measure of discounted future net cash flows relating to estimated proved oil and natural gas reserves is presented below:

	Successor	Predecessor		
	Three Months Ended December 31, 2006	Nine Months Ended September 30, 2006	Year Ended December 31, 2005	Year Ended December 31, 2004
Estimated future cash inflows:				
Revenues from sales of oil and natural gas	$ 405,592	$ 263,003	$ 643,848	$ 298,572
Production costs	(165,968)	(113,414)	(181,962)	(105,108)
Development costs	(11,969)	(5,666)	(15,593)	(719)
Future cash flows before future income taxes	227,655	143,923	446,293	192,745
Future income taxes	—	(31,222)	(76,033)	(32,531)
Future net cash inflows	227,655	112,701	370,260	160,214
10% annual timing discount	(122,652)	(45,406)	(187,851)	(79,442)
Standardized measure of discounted future net cash flows	$ 105,003	$ 67,295	$ 182,409	$ 80,772

At December 31, 2006, as specified by the SEC, the prices for oil and natural gas used in this calculation were regional cash price quotes on the last day of the year except for volumes subject to fixed price contracts. The weighted average prices for the total estimated proved reserves at December 31, 2006, 2005 and 2004 were $60.85 per Bbl of oil and $5.635 per MMBtu of natural gas, $61.04 per Bbl of oil and $10.08 per MMBtu of natural gas, and $43.46 per Bbl of oil and $6.185 per MMBtu of natural gas, respectively. We do not include our oil and natural gas hedging financial instruments, consisting of swaps and collars, in the determination of our oil and natural gas reserves.

Note 18. Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves (Unaudited) – (continued)

The principal sources of changes in the standardized measure of future net cash flows are as follows:

	Successor	Predecessor		
	Three Months Ended December 31, 2006	Nine Months Ended September 30, 2006	Year Ended December 31, 2005	Year Ended December 31, 2004
Beginning of period	$ —	$ 182,409	$ 80,772	$ 74,233
Sales of oil and natural gas, net of production costs	(3,946)	(28,109)	(31,259)	(19,642)
Purchase of minerals in place	84,265	—	15,804	—
Extensions and discoveries	1,638	6,499	36,668	10,971
Development costs incurred	10	7,152	5,097	4,970
Changes in estimated future development costs	(7,372)	2,776	(19,972)	(4,142)
Net changes in prices and production costs	22,300	(147,324)	77,351	8,188
Revisions and other	6,574	7,298	33,207	269
Changes in income taxes	—	22,913	(24,515)	(1,499)
Accretion of 10% timing discount	1,534	13,681	9,256	7,424
End of period	$ 105,003	$ 67,295	$ 182,409	$ 80,772

Note 19. Subsequent Events

In January 2007, we acquired natural gas properties in Michigan, including related hedges, for $71.4 million from certain institutional partnerships managed by EnerVest. The acquisition, which was approved by EV Management’s board of directors, was financed with borrowings under our existing credit facility.

In February 2007, we issued 3.9 million common units to institutional investors in a private placement for $100.0 million, including a $2.0 million contribution by our general partner to maintain its 2% interest in us. We used the proceeds of this issuance to repay all of the indebtedness under our credit facility.

In March 2007, we acquired additional natural gas properties in the Monroe Field in Louisiana from an institutional partnership managed by EnerVest for $95.3 million. The acquisition, which was approved by EV Management’s board of directors, was financed with borrowings under our existing credit facility.

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

We have established and maintain a system of disclosure controls and procedures to provide reasonable assurances that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Based on the evaluation of our disclosure controls and procedures as of the end of the period covered by this report, the principal executive officer and principal financial officer of EV Management have concluded that our disclosure controls and procedures as of December 31, 2006 were effective, at a reasonable assurance level, in ensuring that the information required to be disclosed by us in reports filed under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC.

This Annual Report on Form 10-K does not include a report of management's assessment regarding internal control over financial reporting or an attestation report of our registered public accounting firm due to a transition period established by rules of the SEC for newly public companies.

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, 2006 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 have officers, directors or employees. Our operations and activities are managed by the general partner of our general partner, EV Management, 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.

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.

Directors and Executive Officers

All of our executive management personnel, other than John Walker, Mark Houser and Frederick Dwyer, are employees of EV Management and devote all of their time to our business and affairs. We expect that Mr. Walker will devote approximately 25% of his time to our business, Mr. Houser will initially devote 40% of his time to our business and Mr. Dwyer will devote approximately 25% of his time to our business. The officers of EV Management will manage the day-to-day affairs of our business. We also utilize a significant number of employees of EnerVest to operate our properties and provide us with certain general and administrative services. We reimburse EnerVest for allocated expenses of operational personnel who perform services for our benefit. During the three months ended December 31, 2006, we paid EnerVest a monthly fee of $90,000 (which increased to $165,000 effective February 2007 and increased to $205,000 effective April 2007) for general and administrative services, which fee will increase or decrease as we purchase or divest assets.

The following table shows information as of March 15, 2007 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	61	Chairman and Chief Executive Officer
Mark A. Houser	45	President, Chief Operating Officer and Director
Michael E. Mercer	48	Senior Vice President and Chief Financial Officer
Kathryn S. MacAskie	50	Senior Vice President of Acquisitions and Divestitures
Frederick Dwyer	47	Controller
Victor Burk(1)(2)	57	Director
James R. Larson(1)	57	Director
George Lindahl III(1)(2)	60	Director
Gary R. Petersen(2)	60	Director

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

(2) Member of the compensation committee.

John B. Walker has served as EV Management's Chairman and Chief Executive Officer since 2006. He has been the President and CEO of EnerVest Management Partners, 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. He was the Chairman of the Independent Petroleum Association of America from 2003 to 2005. Mr. Walker is currently a member of the National Petroleum Council and serves or has served on the boards of the Houston Producers Forum, Houston Petroleum Club, Offshore Energy Center, Texas Independent Producers and Royalty Owners Association and the Sam Houston Area Council of the Boy Scouts of America. He holds a BBA from Texas Tech University and an MBA from New York University.

Mark A. Houser has served as EV Management's President, Chief Operating Officer and Director since 2006. He has been the Executive Vice President and Chief Operating Officer of EnerVest Management Partners, Ltd. since 1999. Prior to that, Mr. Houser was Vice President, United States Exploration and Production, for Occidental Petroleum Corporation, or Oxy, where he helped lead Oxy's reorganization of its domestic reserve base. 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.

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

Kathryn S. MacAskie has served as our Senior Vice President of Acquisitions and Divestitures since 2006. She has been President and co-owner of FlairTex Resources, Inc., a petroleum engineering consulting and acquisition business since 2002. Prior to that, Ms. MacAskie was Vice President and Manager of the Houston Office for Cawley, Gillespie & Associates Inc., a Petroleum Engineering Consulting firm from 1999 to 2002 and Senior Vice President of Acquisitions and Divestitures for EnerVest Management Partners, Ltd. from 1994 to 1999. She holds a BS in Engineering from Rice University and is a Licensed Professional Engineer in the State of Texas.

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

Victor Burk was appointed to our Board of Directors in September 2006. Since 2005, Mr. Burk has been 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 board member of the Houston Producers' Forum, 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.

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 and Tax Executives Institute. He holds a BBA in Business from the University of Iowa.

George Lindahl III was appointed to our Board of Directors in September 2006. Since 2001, he has been 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.

Gary R. Petersen was appointed to our Board of Directors in September 2006. Since 1988, Mr. Petersen has been Senior Managing Director of EnCap Investments L.P., an investment management firm which he co-founded. He had previously served as Senior Vice President of the Corporate Finance Division of the Energy Banking Group for RepublicBank Corporation. Prior to his position at RepublicBank, he was Executive Vice President and a member of the Board of Directors of Nicklos Oil & Gas Company from 1979 to 1984. Mr. Petersen is on the board of directors of the general partner of Plains All American Pipeline, L.P., a publicly traded partnership engaged in the transportation and marketing of crude oil. He holds a BBA and an MBA from Texas Tech University.

Composition of the Board of Directors

EV Management's board of directors consists of six members, one of which 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.*

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 Mr. Larson to be 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 has the sole authority to retain and terminate our independent registered public accounting 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 will be given unrestricted access to the audit committee.

Compensation Committee

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.

Conflicts Committee

The conflicts committee is comprised of Messrs. Burk (Chairman), Larson and Lindahl, all of whom meet the independence and experience standards established by the NASDAQ and the Exchange Act. The conflicts committee reviews specific matters that the board of directors believes may involve conflicts of interest. The conflicts committee will then determine if the resolution of the conflict of interest is fair and reasonable to us. 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 the three months ended December 31, 2006, the board of directors had three regularly scheduled and special meetings, the audit committee had one meeting and the compensation committee and conflicts committee had no 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, except for Mr. Lindahl who attended both board meetings but did not attend the audit committee meeting.

Our partnership agreement provides that the general partner will manage and operate 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.

Compliance with Section 16(a) of the Exchange Act

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 the three months ended December 31, 2006, the officer 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).

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.*

Audit Committee Report

REPORT OF THE AUDIT COMMITTEE FOR FISCAL YEAR 2006

Management of EV Management is responsible for our internal controls and the financial reporting process. Deloitte & Touche LLP, our independent registered public accounting firm for the year ended December 31, 2006, is responsible for performing an independent audit of our consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (PCAOB) and generally accepted auditing standards and issuing a report thereon. The audit committee monitors and oversees these processes and approves the selection and appointment of our independent registered public accounting firm and recommends the ratification of such selection and appointment to the board of directors.

The audit committee has reviewed and discussed our audited consolidated financial statements with management and Deloitte & Touche LLP. The audit committee has discussed with Deloitte & Touche LLP the matters required to be discussed by Statement on Auditing Standards No. 61, *Communications with Audit Committees.* The audit committee has received written confirmation of the firm's independence from Deloitte & Touche LLP and has discussed with Deloitte & Touche LLP that firm's independence.

Based on the foregoing review and discussions and such other matters the audit committee deemed relevant and appropriate, the audit committee recommended to the board that the audited consolidated financial statements of the partnership be included in our Annual Report on Form 10-K for the year ended December 31, 2006.

Members of the Audit Committee:

James R. Larson, Chairman
Victor Burk
George Lindahl III

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 reimburse EnerVest for the payment of general and administrative services incurred 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. Walker, Mr. Houser and Mr. Dwyer are compensated by EnerVest, and no expense associated with their compensation is directly charged to or reimbursed by us. The only exception is with respect to equity compensation paid by us. The compensation of the remaining executive officers of EV Management is set by the compensation committee of EV Management's board of directors. The officers and employees of EV Management may participate in employee benefit plans and arrangements sponsored by EnerVest.

In this compensation discussion and analysis, we discuss our compensation objectives, our decisions and the rationale behind those decisions relating to 2006 compensation for our named executive officers identified in the Summary Compensation Table.

Objectives of Our Compensation Program

Our primary business objective is to provide stability and growth in our cash distributions per unit over time. We intend to accomplish this objective by executing the following business strategies:

- continually maintain an inventory of proved undeveloped drilling locations, which are sufficient when drilled and completed to allow us to maintain our production levels over the near-term;
- replace and increase our reserves and production over the long term by pursuing acquisitions of long-lived producing oil or natural gas properties with low decline rates, predictable production profiles and relatively low risk drilling opportunities;
- maintain low levels of indebtedness to permit us to finance opportunistic acquisitions;
- reduce exposure to commodity price risk through hedging;
- retain control over the operation of a substantial portion of our production; and
- focus on controlling the costs of our operations.

Our compensation program is designed to attract, retain, and motivate employees in order to effectively execute our business strategies.

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. In addition, we reward qualities that we believe help achieve our strategy such as teamwork; individual performance in light of general economic and industry specific conditions; performance that supports our core values; resourcefulness; the ability to manage our existing assets; the ability to explore new avenues to increase oil and gas production and reserves; level of job responsibility; and tenure.

Elements of Our Compensation Program and Why We Pay Each Element

Our compensation program is comprised of four elements: base salary, cash bonus, long-term equity-based compensation and benefits.

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.

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. We also provide an annual cash bonus in order to be competitive from a total remuneration standpoint.

Long-term equity-based incentive 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; to encourage executive retention; and to give executives the opportunity to share in our long-term performance. In September 2006, the board of directors and unitholders approved our Long-Term Incentive Plan. For a detailed description of this plan, see “Long-Term Incentive Plan.”

We offer benefits such as matching 401(k) contributions and payment of insurance premiums in order to provide a competitive remuneration package.

Because Messrs. Walker, Houser and Dwyer only commit less than half of their business time to us, the committee believes that it is appropriate to compensate them only through long-term incentives to retain them during the period of time during which their contributions are expected to impact our business and that will reward them in accordance with the success of those long-term goals and policies.

How We Determine Each Element of Compensation

The compensation committee of EV Management’s board of directors oversees 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 expects to meet in the fourth quarter of each year to review the compensation program and to determine compensation levels for the ensuing fiscal year.

Base salary. Mr. Mercer and Ms. MacAskie are parties to employment agreements which set their minimum base salaries per annum. These salaries were determined by private negotiations between those officers and EnerVest prior to our initial public offering. Pursuant to their employment arrangements (which are described in more detail in the narrative discussion that follows the Summary Compensation Table), Mr. Mercer's base salary is not less than $200,000 per year and Ms. MacAskie's base salary is not less than $175,000 per year. In the three months ended December 31, 2006, each of these executive officers' salaries equaled their respective minimum amounts on a pro rata basis. Neither we, the compensation committee nor our general partner have engaged in any benchmarking of these salaries against those of similarly situated executives in peer companies.

In the compensation committee's discretion, these base salaries may be increased. To determine whether or not to increase the minimum base salary set forth in the employment agreement, the committee intends to take into account a combination of subjective factors as well as data available from objective, professionally-conducted market studies obtained from a range of industry and general market sources. Subjective factors the committee intends to consider include individual achievements, the partnership's performance, level of responsibility, experience, leadership abilities, increases or changes in duties and responsibilities and contributions to our performance.

Bonus. For 2006, Mr. Mercer and Ms. MacAskie were paid the minimum bonus amounts set forth in their employment agreements. These bonus amounts were determined by private negotiations between those officers and EnerVest prior to our initial public offering and were intended to reflect the officers' contributions to the successful consummation of our initial public offering. The employment agreements provide that for the fiscal years after 2006, the cash bonus element of compensation will be equal to a percentage of the executive's base salary paid during each such annual period and will be payable only if the executive has met pre-established performance criteria, all as determined by the compensation committee.

In establishing future bonus amounts, the compensation committee intends to set various targets for measures such as pre-tax income, cash flows from operations, and oil and natural gas productions levels. The executive can receive a percentage of his salary based on the level of achievement of these targets. The granting of a bonus to any individual or to the officers as a group is entirely at the discretion of our committee. The compensation committee may choose to award the bonus or not, and decide on the actual level of the award in light of all relevant factors after completion of the fiscal year.

Long-Term Equity-Based Incentives. The compensation committee and/or our board of directors act as the manager of our incentive plans and performs functions that include selecting award recipients, determining the timing of grants and assigning the number of units subject to each award, fixing the time and manner in which awards are exercisable, setting exercise prices and vesting and expiration dates, and from time to time adopting rules and regulations for carrying out the purposes of our plans. 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 committee maintains the discretionary authority to vest the equity grant immediately if the individual situation merits. In the event of a change of control, or upon the death, disability, retirement or termination of a grantee's employment without good reason, all outstanding equity-based awards will immediately vest.

Except as set forth in the employment agreements, 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, we intend to take into consideration discretionary factors such as the individual's current and expected future performance, level of responsibilities, retention considerations, survey data and the total compensation package.

In accordance with their employment agreements, Mr. Mercer and Ms. MacAskie are eligible for specified minimum unit awards. The amounts of these awards were determined by private negotiations between those officers and EnerVest prior to our initial public offering and were intended to reflect the officers' respective contributions to the successful completion of the offering, to align their interests with the interests of our unitholders, and to provide and incentive for future performance.

Although the Plan generally provides for the grant of stock options, Internal Revenue Code Section 409A and authoritative guidance thereunder provides that stock 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 stock options on units of the partnership.

Benefits. The costs of benefits for executives (other than Mr. Walker, Mr. Houser and Mr. Dwyer) and other employees of EV Management are charged monthly to us. These executive officers and employees participate in the available retirement plans of EnerVest. Through EnerVest, we provide company benefits, or perquisites, that we believe are standard in the industry. These benefits consist of a group medical and dental insurance program for employees and their qualified dependents, group life insurance for employees and their spouses, accidental death and dismemberment coverage for employees, a company sponsored cafeteria plan and a 401(k) employee savings and protection plan. The 401(k) contribution to each qualified participant, including the named executive officers, is calculated based on 5% of the employee's eligible salary, excluding annual cash bonuses. We also match employee deferral amounts, including amounts deferred by named executive officers, up to a total of 5% of eligible compensation.

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- 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 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.

Accounting and Tax Considerations

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

Unit Ownership Policy

Currently, we do not have a unit ownership policy that applies to our employees.

Compensation Committee Report

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

Compensation Committee:

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

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, 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.

Summary Compensation Table

The following table sets forth certain information with respect to compensation of our named executive officers. EV Management was formed in April 2006, but conducted no business until October 1, 2006. Accordingly, the compensation set forth below includes compensation paid to each of the named executive officers for the period from October 1, 2006 through December 31, 2006. There was no compensation awarded to, earned by or paid to any of the named executive officers related to option awards or non-equity incentive compensation plans. In addition, none of the named executive officers participate in a defined benefit pension plan. During 2006, Mr. Dwyer did not receive compensation of over $100,000 from us or any of our predecessors and therefore is not required to be included in the summary compensation table.

Name and Principal Position	Year	Salary(1) ($)	Bonus(2) ($)	Unit Awards(3) ($)	All Other Compensation(4) ($)	Total ($)
John B. Walker Chief Executive Officer	2006	—	—	450,000	—	450,000
Mark A. Houser President, Chief Operating Officer	2006	—	—	450,000	—	450,000
Michael E. Mercer Senior Vice President, Chief Financial Officer	2006	50,000	200,000	1,200,000	—	1,450,000
Kathryn S. MacAskie Senior Vice President of Acquisitions and Divestitures	2006	43,750	100,000	1,000,000	—	1,143,750

(1) Salaries set forth in the preceding table represent the amounts paid to the listed executives for the period October 1, 2006 through December 31, 2006. Pursuant to their employment agreements with EV Management, Mr. Mercer is entitled to an annual minimum salary of $200,000 and Ms. MacAskie is entitled to an annual minimum salary of $175,000. We reimburse EV Management for Mr. Mercer's and Ms. MacAskie's salaries. Messrs. Walker and Houser are compensated by EnerVest, and we do not reimburse EnerVest for the costs of their compensation. Mr. Walker does not receive any compensation for his position as a member of the board of directors.

(2) The bonuses set forth in the preceding table represent amounts paid to the listed executives in December 2006 as bonuses for service in 2006. We reimburse EV Management for Mr. Mercer's and Ms. MacAskie's bonuses. Both Mr. Mercer's and Ms. MacAskie's bonuses were earned pursuant to their employment agreements with EV Management.

(3) As discussed under "EV Investors" below, EV Properties issued a limited partnership interest (the "Profits Interest") to EV Investors, a limited partnership formed by Messrs. Walker, and Mercer and Ms. MacAskie. The Profits Interest entitled EV Investors to receive 5% of any increase in the value of the assets of EV Properties, and the partnership agreement of EV Investors stated that any amount received by EV Investors with respect to the Profits Interest would be distributed to Messrs. Walker, Houser and Mercer and Ms. MacAskie as limited partners. In connection with our initial public offering, EV Investors contributed the Profits Interest to us in exchange for 155,000 of our subordinated units. The partnership agreement of EV Investors provides that Messrs. Walker, Houser and Mercer and Ms. MacAskie are entitled to their proportionate share of any distributions received by EV Investors with respect to their share of the subordinated units, and to receive any common units into which the subordinated units convert. The amounts set forth in this table represent the

number of subordinated units attributable to the limited partnership interest of the named executive officer multiplied by $20.00, the price to the public of the common units in our limited public offering. The value of the subordinated units may be less than the value of the common units because of the subordination terms in our partnership agreement and the lack of a public market for the units.

(4) All other compensation benefits received in 2006 were less than $10,000.

Employment Contracts

EV Management entered into an employment agreement with Mr. Mercer that provides that he will act as Senior Vice President and Chief Financial Officer of EV Management until December 31, 2007, subject to automatic one year renewals of the term if neither party submits a notice of termination at least sixty days prior to the end of the then-current term. This agreement may be terminated by either party, at any time, subject to severance obligations in the event Mr. Mercer is terminated by EV Management without cause or he dies or is disabled.

Mr. Mercer's employment agreement provides for a minimum base salary of $200,000, subject to upward adjustment by the compensation committee or EV Management's board of directors, and a minimum bonus at the end of 2006 of $200,000. Thereafter, Mr. Mercer is entitled to an annual bonus equal to a percentage of his base salary based on the achievement of performance criteria for the applicable period, all as determined by the compensation committee. The agreement also provides that Mr. Mercer is eligible for the following restricted common unit awards under the Plan: a minimum of 7,500 units at December 31, 2006 and a minimum of 7,500 units at December 31, 2007, provided that Mr. Mercer remains an employee on such date.

Mr. Mercer will be entitled to a lump sum severance payment in the event of voluntary or involuntary termination following a change of control of EV Management or EnerVest, equal to two times his annual base salary in effect on the termination date and all unit awards shall vest. Mr. Mercer will also be entitled to receive medical, dental and life insurance benefits following a severance triggering termination at the cost charged by EV Management to its remaining executive officers. See "Termination and Change of Control Provisions."

EV Management also entered into an employment agreement with Kathryn MacAskie as Senior Vice President of Acquisitions and Divestitures. Ms. MacAskie's employment has the same terms as Mr. Mercer's, except that her base salary during 2006 was $175,000 per annum, and she was entitled to a minimum bonus of $100,000 at the end of 2006. She was eligible to receive a minimum of 12,500 restricted common units at December 31, 2006 and will be eligible to receive a minimum of 12,500 restricted common units at the end of 2007.

EV Investors

When EV Properties was formed in May 2006, EV Investors was issued a limited partnership interest in EV Properties that generally entitled EV Investors to receive 5% of the appreciation in value of EV Properties. The general partner of EV Investors is EnerVest (with a nominal interest), and the limited partners of EV Investors are Messrs. Walker, Houser and Mercer and Ms. MacAskie. EV Properties issued the limited partnership interest to EV Investors as incentive compensation to Messrs. Walker, Houser and Mercer and Ms. MacAskie. In connection with the closing of our initial public offering, EV Investors transferred its limited partnership interest in EV Properties to us in exchange for 155,000 subordinated units. Under the partnership agreement of EV Investors, the limited partners of EV Investors will be entitled to all of the distributions attributable to the 155,000 subordinated units held by EV Investors. In addition, if these limited partners do not forfeit their limited partnership interests, they will be entitled to have distributed to them their share of the subordinated units. The limited partnership interests of EV Investors are generally subject to forfeiture if, prior to the end of the forfeiture period, the executive officer voluntarily resigns his employment or is terminated for cause. The forfeiture period terminates as to half of the limited partnership interest on September 30, 2007 and the other half on September 30, 2008.

The limited partner interests in EV Investors owned by the executive officers of EV Management and the number of subordinated units with respect to which the executive officer will receive dividends and be entitled to receive upon termination of the forfeiture period, is listed below:

Name	Percent Interest	Subordinated Units
John B. Walker	14.5%	22,500
Mark A. Houser	14.5%	22,500
Michael E. Mercer	38.7%	60,000
Kathryn S. MacAskie	32.3%	50,000
Total	100.0%	155,000

In addition, in connection with the closing of our initial public offering, EV Investors purchased a 5% limited partnership interest in our general partner for $144,500 (the proportionate value of a 5% interest in our general partner). EnerVest and certain of the executive officers of EV Management contributed $144,500 to EV Investors and received Class A limited partnership interests in EV Investors entitling them to distributions of any amounts received by EV Investors attributable to the interest in our general partner acquired by EV Investors. The names of the executive officers and the indirect percent interest in our general partner that they acquired through their ownership in EV Investors are set forth below:

Name	Percent Interest
Michael E. Mercer	1.5%
Kathryn S. MacAskie	1.0%
EnerVest	2.5%
Total	5.0%

If an executive officer ceases to be an executive officer of EV Management, EV Investors will have the option to purchase the indirect ownership interest in our general partner from such former executive officer for the fair market value of such interest.

EnerVest and EnCap also have a limited partnership interest in EV Investors entitling them to any distributions made by EV Investors attributable to any limited partnership interest owned by an executive officer which was forfeited or purchased by EV Investors, until such time, if any, that such interest is issued to another executive officer of EV Management. The interest of EnerVest in such distributions is 75% and the interest of EnCap is 25%.

Long-Term Incentive Plan

The board of directors adopted the Plan on September 20, 2006. Awards under the Plan may be unit options, phantom 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 775,000 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 or the board of directors administers the Plan.

Generally, upon vesting, a phantom unit entitles the participant to a common unit or an amount of cash equal to the fair market value of a common unit, as determined by the plan administrator. The plan administrator will determine the number of phantom units to be granted, any restricted period, the conditions under which phantom units may become vested or forfeited and any other terms and conditions, all as specified in the applicable award agreement. Unless waived by the plan administrator or the award agreement provides otherwise, all outstanding phantom units will be forfeited upon termination of a participant’s employment with, or consulting services to, the general partner and its affiliates or upon termination of a participant’s membership on the board of directors of the general partner.

Restricted unit awards are subject to a restricted period, which is a period of time established by the plan administrator and during which the award is subject to forfeiture and is not exercisable or payable to the participant, as applicable. The plan administrator will determine the number of restricted units to be granted, the restricted period, the conditions under which restricted units may become vested or forfeited and any other terms and conditions, all as specified in the applicable award agreement. Unless waived by the plan administrator or the award agreement provides otherwise, all outstanding restricted units will be forfeited upon termination of a participant’s employment with, or consulting services to, the general partner and its affiliates or upon termination of a participant’s membership on the board of directors of the general partner.

In the plan administrator's discretion, an award may provide that distributions made with respect to the restricted units are subject to the same forfeiture and other restrictions as the restricted units and that the distributions will be held, without interest, until the restricted unit vests or is forfeited. Absent a restriction on distributions, distributions will be paid to the holder of the restricted units without restriction.

The plan administrator may, in its discretion, grant DERs to eligible participants. A DER is a contingent right to receive an amount in cash equal to the cash distributions made by us with respect to a unit during the period the award is outstanding. The plan administrator will determine whether DERs are tandem or separate awards and how such awards are paid to participants. The award agreement will contain the vesting schedule and the payment provisions applicable to the award.

Outstanding Equity Awards at Fiscal Year End

There were no outstanding equity awards at December 31, 2006.

Option Exercises and Unit Vested Table during 2006

No equity awards vested during 2006.

Termination of Employment and Change-in-Control Provisions

Mr. Mercer and Ms. MacAskie are parties to employment agreements with EV Management which provide them 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 the officer's termination was effective as of December 31, 2006 and that phantom units awarded in January 2007 had been awarded as of December 31, 2006. In presenting this disclosure, we describe amounts earned through December 31, 2006 and, in those cases where the actual amounts to be paid out can only be determined at the time of such executive's separation from EV Management, our estimates of the amounts which would be paid out to the executives upon their termination.

Provisions Under the Employment Agreements

Under the employment agreements, if the executive's employment with EV Management and its affiliates terminates, the executive is entitled to unpaid salary for the full month in which the termination date occurred. However, if the executive is terminated for cause, the executive is only entitled to receive accrued but unpaid salary through the termination date. In addition, if the executive's employment terminates, the executive 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 the executive's employment is involuntarily terminated by EV Management (except for cause or due to the death of the executive) or if the executive's 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 the executive's base salary in effect as of the termination date. Assuming termination as of December 31, 2006, for Mr. Mercer, this amount would have been $400,000, and for Ms. MacAskie, this amount would have been $350,000. In addition, the executive is entitled to continued group health plan coverage following the termination date for the executive and the executive's eligible spouse and dependents for the maximum period for which such qualified beneficiaries are eligible to receive COBRA coverage. Executive 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 termination as of December 31, 2006, for Mr. Mercer, this amount would have been $25,100, and for Ms. MacAskie this amount would have been $16,749.

In the event an executive'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, the executive 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, 2006, for Mr. Mercer, this amount would have been $400,000 representing 104 weeks of base salary, $1,406,400 representing vesting of unvested units, and $25,100 representing COBRA coverage. For Ms. MacAskie, this amount would have been $350,000 representing 104 weeks of base salary, $1,172,000 representing vesting of unvested units, and $16,749 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:

- the executive's 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 the executive of a demonstrable act of fraud, or a misappropriation of funds or property, of or upon the company or any affiliate;
- the engagement by the executive 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 the executive of the employment agreement, or the repeated nonperformance of executive's duties to the company or any affiliate (other than by reason of illness or incapacity).

In some cases, the executive 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 us 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 the executive's employment for normal retirement at or after attaining age sixty-five provided that executive has been with the company for at least five years.

Provisions Under Phantom Unit Award Agreements

Mr. Mercer and Ms. MacAskie were granted phantom units in January 2007. The award agreements provide that any unvested units will vest upon the executive's death, disability, termination of employment other than for cause and upon a change of control. If the phantom unit grants would have occurred on or prior to December 31, 2006, and assuming termination of employment or change of control as of December 31, 2006, for Mr. Mercer, the value of the awards would have been $175,800, and for Ms. MacAskie, the value of the awards would have been $293,000. If the executive resigns or his or her 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

Officers or employees of EV Management or its affiliates who also serve as directors do not receive additional compensation for their service as a director of EV Management. Directors who are not officers or employees of EV Management or its affiliates receive an annual retainer of $25,000, with the chairman of the audit committee receiving an additional annual fee of $4,000 and the chairmen of the compensation committee and conflicts committee receiving an additional annual fee of $2,000. In addition, each non-employee director is reimbursed for his out of pocket expenses in connection with attending meetings of the board of directors or committees. We indemnify each director for his actions associated with being a director to the fullest extent permitted under Delaware law. In addition, each of our directors who are not employees of EV Management or EnerVest received 1,250 phantom units in January 2007 under our Plan.

The following table sets forth certain information with respect to compensation of EV Management's directors. EV Management was formed in April 2006, but conducted no business until October 1, 2006. Accordingly, the compensation set forth below includes compensation paid to each of the directors for the period from October 1, 2006 through December 31, 2006. There was no compensation awarded to, earned by or paid to any of the directors related to stock awards, option awards or non-equity incentive compensation plans for services in 2006.

Name	Fees Earned or Paid in Cash	All Other Compensation(1)	Total
Victor Burk	$ 7,750	$ —	$ 7,750
James R. Larson	8,250	—	8,250
George Lindahl III	6,750	—	6,750
Gary R. Petersen	—	—	—

(1) There was no reportable other compensation.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters

The following table sets forth the beneficial ownership of our units as of March 15, 2007 held by:

- each person know by us to beneficially own 5% or more of our common or subordinated 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	Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned	Percentage of Common Units and Subordinated Units Beneficially Owned
5% Beneficial Owner:					
ZLP Fund, L.P. 45 Broadway – 28th Floor New York, NY 10006	565,692	6.7%	—	—	4.9%
Officers and Directors:					
John B. Walker(2)	156,604	2.2%	2,663,830	85.9%	24.5%
Mark A. Houser(3)	600	*	22,500	*	*
Michael E. Mercer(4)	—	—	60,000	1.9%	*
Kathryn S. MacAskie(5)	1,000	*	50,000	1.6%	*
Frederick Dwyer	2,500	*	—	—	*
Victor Burk	—	—	—	—	—
James R. Larson	1,000	*	—	—	*
George Lindahl III	—	—	—	—	—
Gary R. Petersen(6)	23,696	*	436,170	14.1%	4.0%
All directors and executive officers as a group (9 persons)	185,400	2.2%	3,100,000	100.0%	28.5%

* Less than 1%

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

(2) Includes (i) 44,000 common units and 810,030 subordinated units owned by EnerVest, (ii) 92,304 common units and 1,698,800 subordinated units owned by CGAS Exploration and (iii) 155,000 subordinated units owned by EV Investors. 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 and subordinated units beneficially owned by EnerVest, and EnerVest may be deemed to be the beneficial owner of the common and subordinated units owned by CGAS Exploration and EV Investors. CGAS Exploration is owned by EnerVest partnerships. EnerVest, as the general partner of the EnerVest partnerships that own CGAS Exploration, has the power to direct the voting and disposition of the common units and subordinated units owned by CGAS Exploration, and may therefore be deemed to beneficially own such units. EnerVest, as the general partner of EV Investors, has the power to direct the voting and disposition of the subordinated units owned by EV Investors, and may therefore be deemed to beneficially own such units. Mr. Walker disclaims beneficial ownership of the units owned by EnerVest, CGAS Exploration and EV Investors.

(3) Includes 22,500 subordinated units owned by EV Investors. As a limited partner of EV Investors, Mr. Houser is entitled to distributions made with respect to the subordinated units, and may be entitled to receive a distribution of the subordinated units in the future. Mr. Houser disclaims beneficial ownership of the subordinated units owned by EV Investors.

(4) Includes 60,000 subordinated units owned by EV Investors. As a limited partner of EV Investors, Mr. Mercer is entitled to distributions made with respect to the subordinated units, and may be entitled to receive a distribution

of the subordinated units in the future. Mr. Mercer disclaims beneficial ownership of the subordinated units owned by EV Investors.

(5) Includes 50,000 subordinated units owned by EV Investors. As a limited partner of EV Investors, Ms. MacAskie is entitled to distributions made with respect to the subordinated units, and may be entitled to receive a distribution of the subordinated units in the future. Ms. MacAskie disclaims beneficial ownership of the subordinated units owned by EV Investors.

(6) Includes 13,232 common units and 243,350 subordinated units owned by EnCap Energy Capital Fund V, L.P. and 10,464 common units and 192,820 subordinated units owned by EnCap Energy Capital Fund V-B, L.P. EnCap Equity Fund V GP, L.P., as the general partner of each of EnCap Energy Capital Fund V, L.P. and EnCap Energy Capital Fund V-B, L.P., EnCap Investments L.P., as the general partner of EnCap Equity Fund V GP, L.P., EnCap Investments GP, L.L.C., as the general partner of EnCap Investments L.P., RNBD GP LLC, as the sole member of EnCap Investments GP, L.L.C., and David B. Miller, Gary R. Petersen, D. Martin Phillips, and Robert L. Zorich, as the members of RNBD GP LLC may be deemed to share voting and dispositive control over the subordinated units and common units owned by EnCap Energy Capital Fund V, L.P. and EnCap Energy Capital Fund V-B, L.P. Each of EnCap Equity Fund V GP, L.P., EnCap Investments L.P., EnCap Investments GP, L.L.C., RNBD GP LLC, David B. Miller, Gary R. Petersen, D. Martin Phillips, and Robert L. Zorich disclaim beneficial ownership of the reported securities in excess of such entity's or person's respective pecuniary interest in the securities.

Beneficial Ownership of Our General Partner

EV Management, the general partner of our general partner, is a limited liability company wholly-owned by EnerVest, a limited partnership. Messrs. Jon Rex Jones and A.V. Jones 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 Mr. John Rex Jones and Mr. A.V. Jones, and the members of EnerVest's executive management team which own interests in EnerVest, is 1001 Fannin Street, Suite 800, Houston, Texas 70002.

Securities Authorized for Issuance under Equity Compensation Plans

The following table summarizes information about our equity compensation plans as of December 31, 2006:

	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	—	—	775,000
Equity compensation plans not approved by security holders	—	—	—
Total	—	—	775,000

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

Item 13. Certain Relationships and Related Transactions, and Director Independence

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

Our general partner, EV Energy GP, is owned 71.25% by EnerVest, 23.75% by EnCap and 5% by EV Investors. Our general partner has a 2% interest in us and owns the incentive distribution rights, which entitle our general partner to a portion of the distributions we make. The distributions we will make to our general partner are described under Item 5. While EnerVest, EV Investors and CGAS Exploration 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.

In addition to its 5% limited partner interest in our general partner, EV Investors owns 155,000 subordinated units. EV Investors owned an interest in one of our predecessors, which it conveyed to us for the subordinated units in connection with our initial public offering. EV Investors received its interest in our predecessors for nominal consideration. EV Investors has outstanding two classes of limited partner interests:

- Class A interests, which entitle the holder to all distributions attributable to the 5% interest owned by EV Investors in our general partner, and
- Class B interests, which entitle the holders to all distributions attributable to the 155,000 subordinated units owned by EV Investors, and to receive a distribution of such subordinated units when they convert to common units.

The Class A interests are subject to purchase by EnerVest if the holder of the interest terminates his or her employment with EV Management and the Class B interests are subject to forfeiture if the holder voluntarily terminates his or her employment with EV Management prior to September 30, 2007 (with respect to the interest representing half of the subordinated units) and September 30, 2008 (with respect to the other half).

The limited partner interests in EV Investors owned by the executive officers of EV Management and the number of subordinated units with respect to which the executive officer will receive distributions and be entitled to receive upon termination of the forfeiture period, are set forth below:

Name	Percent Interest	Subordinated Units
John B. Walker	14.5%	22,500
Mark A. Houser	14.5%	22,500
Michael E. Mercer	38.7%	60,000
Kathryn S. MacAskie	32.3%	50,000
Total	100.0%	155,000

The names of the executive officers and the indirect percent interest in our general partner that each officer owns in our general partner by reason of their ownership of Class A interests in EV Investors they acquired through their ownership in EV Investors are set forth below:

Name	Percent Interest
Michael E. Mercer	1.5%
Kathryn S. MacAskie	1.0%
EnerVest	2.5%
Total	5.0%

EnerVest and EnCap also own a limited partnership interest in EV Investors that entitles them to any distributions made by EV Investors attributable to any limited partnership interests owned by an executive officer which is forfeited or purchased by EV Investors, until such time, if any, that such interest is issued to another executive officer of EV Management. The interest of EnerVest in such distributions is 75% and the interest of EnCap is 25%.

We did not make any distributions to our general partner or with respect to our subordinated units during 2006.

Contracts with EnerVest and Its Affiliates

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

We have entered into agreements with EnerVest. The following is a description of those 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 of $90,000 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 will indemnify us until September 29, 2007 against certain potential environmental claims, losses and expenses associated with the operation of the assets occurring before September 29, 2006. Additionally, EnerVest will indemnify us for losses attributable to title defects, retained assets and liabilities (including any preclosing litigation relating to assets contributed to us) and income taxes attributable to pre-closing operations. EnerVest's maximum liability for these indemnification obligations will not exceed $1.5 million and EnerVest will not have any obligation under this indemnification until our aggregate losses exceed $200,000. EnerVest will have no indemnification obligations with respect to environmental claims made as a result of additions to or modifications of environmental laws promulgated after September 29, 2006. We have agreed to indemnify EnerVest against environmental liabilities related to our assets to the extent EnerVest is not required to indemnify us. 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 the three months ended December 31, 2006, we paid EnerVest $270,000 in monthly fees under the omnibus agreement. In connection with our acquisition of oil and natural gas properties in January 2007, the monthly fee under the omnibus agreement was increased from $90,000 to $165,000 as of February 1, 2007 and, in connection with our acquisition of additional oil and natural gas properties in the Monroe Field in Louisiana, the monthly fee under the omnibus agreement was increased from $165,000 to $205,000 as of April 1, 2007.

Operating Agreements

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

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

Under the COPAS model form, direct expenses include the costs of third party services performed on our properties and well, gathering and other equipment used on our properties. In addition, direct expenses will include the allocable share of the cost of the EnerVest employees who perform services on our properties. The allocation of the cost of EnerVest employees who perform services on our properties are based on time sheets maintained by

EnerVest's employees. Direct expenses charged to the joint account will also include an amount determined by EnerVest to be the fair rental value of facilities owned by EnerVest and used in the operation of our properties.

During the three months ended December 31, 2006, we reimbursed EnerVest approximately $0.6 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.

Natural Gas Gathering Arrangements.

A portion of our natural gas production in Northern Louisiana was sold to EnerVest Monroe Marketing, a subsidiary of a partnership in which EnerVest owns a 1% general partnership interest. The purchase price was the spot market price based on the average of two index prices for natural gas production in the area, less a gathering fee of either $0.10 per Mcf or $0.75 per Mcf depending upon whether compression and additional gathering services or facilities are provided. EnerVest Monroe Marketing resells the gas, typically at a price based on one of the two indices for natural gas production in the area used to calculate our purchase price. EnerVest Monroe Marketing will therefore realize a profit or loss on resales of our natural gas production when there is a difference between the average of the two indices used to calculate our purchase price and the index at which EnerVest Monroe Marketing resells its production. During the three months ended December 31, 2006, EnerVest Marketing realized a profit of $0.1 million on sales of our natural gas production under this arrangement.

Purchase of Oil and Natural Gas Properties from EnerVest and Its Affiliates

We may, from time to time, purchase oil and natural gas properties from entities affiliated with EnerVest. During the three months ended December 31, 2006, we did not purchase any assets from EnerVest or its affiliates, other than in connection with our formation when we closed our initial public offering.

In connection with the closing of our initial public offering, we acquired limited partnerships which owned oil and natural gas properties from EnerVest and its affiliates (including EV Investors) and from EnCap. In exchange for these assets,

- EnerVest received a 71.25% interest in our general partner, EV Investors received a 5.0% interest in our general partner and EnCap received a 23.75% interest in our general partner;
- Our general partner received a 2% general partnership interest and all of the incentive distribution rights;
- EnerVest received 163,625 common units, 810,030 subordinated units and a cash payment of $16.0 million;
- EV Investors received 155,000 subordinated units;
- EnCap received 88,120 common units, 436,170 subordinated units and a cash payment of $8.6 million; and
- CGAS Exploration received 343,255 common units, 1,698,800 subordinated units and a cash payment of $33.7 million.

In addition, we used a portion of the proceeds of the offering to repay $10.4 million of indebtedness of our predecessors that we assumed in connection with the consummation of the offering. We also assumed natural gas hedges to which one of our predecessors were a party.

In connection with the formation of EV Properties in the second quarter of 2006, certain of our predecessors sold non-material assets not used in their oil and natural gas activities. These transactions are described below:

- Our predecessors sold oil and natural gas properties with a book value of $0.4 million to a wholly owned subsidiary of EnerVest;
- Our predecessors sold other property totaling $0.2 million to a wholly owned subsidiary of EnerVest; and
- Our predecessors sold investments in affiliated companies totaling $1.3 million to a wholly owned subsidiary of EnerVest.

In addition, in connection with the contribution of the general partner and limited partner interests in certain of our predecessors, accounts payable of $3.2 million was forgiven by EnerVest and converted to owners' equity.

Acquisition of Properties from EnerVest Partnerships in 2007

In January 2007, we acquired oil and natural gas properties in Michigan for $71.4 million from certain institutional partnerships in which EnerVest has a 26% general partner interest.

In March 2007, we acquired oil and natural gas properties in the Monroe Field in Louisiana for $95.3 million from an institutional partnership in which EnerVest has a 1% general partner interest. EnerVest will receive approximately $3.0 million of the net proceeds.

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, Independent Registered Public Accounting Firm, to audit our consolidated financial statements for the three months ended December 31, 2006. 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 were approved by the audit committee.

Fees paid to Deloitte & Touche LLP for 2006 by us and our predecessors are as follows:

	Successor	Predecessors	Total
Audit fees(1)	$ 663,780	$ 907,692	$ 1,571,472
Audit-related fees	—	—	—
Tax fees	—	92,040	92,040
All other fees	—	—	—
Total	$ 663,780	$ 999,732	$ 1,663,512

(1) Represents fees for professional services provided in connection with the audit of our annual financial statements, review of our quarterly financial statements and audits performed as part of our registration filings.

PART IV

Item 15. Exhibits, Financial Statement Schedules

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

(1) Financial Statements

All financial statement 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:

1.1 Underwriting Agreement, dated September 26, 2006 by and among EnerVest Management Partners, Ltd., EV Management, LLC, EV Energy GP, L.P., EV Energy Partners, L.P., EV Properties GP, LLC, EV Properties, LP, CGAS Holdings, LLC, EVEC Holdings, LLC, EnCap Energy Capital Fund V, L.P., EnCap V-B Acquisitions, L.P. and A.G. Edwards & Sons, Inc., Raymond James & Associates, Inc., Wachovia Capital markets, LLC and Oppenheimer & Co. Inc. (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 5, 2006).

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).

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 Contribution Agreement, dated September 29, 2006, by and among EnerVest Management Partners, Ltd., EVEC Holdings, LLC, EnerVest Operating, L.L.C., CGAS Exploration, Inc., EV Investors, L.P., , EVCG GP LLC, CGAS Properties, L.P., CGAS Holdings, LLC, EnCap Energy Capital Fund V, L.P., EnCap V-B Acquisitions, L.P., EnCap Fund V, EV Management, LLC, EV Energy GP, L.P., and EV Energy Partners, L.P. (Incorporated by reference from Exhibit 10.5 to EV Energy Partners, L.P.'s current report on Form 8-K filed with the SEC on October 5, 2006).

10.6 Credit Agreement, dated September 29, 2006, by and among EV Properties, L.P. and JPMorgan Chase Bank, N.A., as administrative agent for the lenders named therein. (Incorporated by reference from Exhibit 10.6 to EV Energy Partners, L.P.'s current report on Form 8-K filed with the SEC on October 5, 2006).

*10.7 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).

*10.8 Employment Agreement, dated October 1, 2006, by and between EV Management, LLC and Kathryn S. MacAskie. (Incorporated by reference from Exhibit 10.8 to EV Energy Partners, L.P.'s current report on Form 8-K filed with the SEC on October 5, 2006).

10.9 Purchase and Sale Agreement by and among EV Properties, L.P. and Five States Energy Company, LLC dated November 10, 2006 (Incorporated by reference from Exhibit 2.1 to EV Energy Partners, L.P.'s current report on Form 8-K filed with the SEC on November 17, 2006).

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+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

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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: March 27, 2007

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

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

Signature	Title	Date
/s/ John B. Walker John B. Walker	Chairman and Chief Executive Officer (principal executive officer)	March 27, 2007
/s/ Mark A. Houser Mark A. Houser	President, Chief Operating Officer and Director	March 27, 2007
/s/ Michael E. Mercer Michael E. Mercer	Senior Vice President and Chief Financial Officer (principal financial officer)	March 27, 2007
/s/ Frederick Dwyer Frederick Dwyer	Controller (principal accounting officer)	March 27, 2007
/s/ Victor Burk Victor Burk	Director	March 27, 2007
/s/ James R. Larson James R. Larson	Director	March 27, 2007
/s/ George Lindahl III George Lindahl, III	Director	March 27, 2007
/s/ Gary R. Petersen Gary R. Petersen	Director	March 27, 2007

EXHIBIT INDEX

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+32.2 Section 1350 Certification of Chief Financial Officer

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* Management contract or compensatory plan or arrangement

\+ Filed herewith

Exhibit 21.1

EV ENERGY PARTNERS, L.P.
Subsidiaries

Subsidiary		Jurisdiction of Formation
1.	EV Properties GP, LLC	Delaware
2.	EV Properties, L.P.	Delaware
3.	EVCG GP, LLC	Delaware
4.	CGAS Properties, L.P.	Delaware
5.	EVPP GP, LLC	Delaware
6.	EnerVest Production Partners, Ltd.	Texas
7.	EnerVest Cargas, Ltd.	Texas
8.	Lower Cargas Operating Company, LLC	Louisiana

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
www.cgaus.com

1000 LOUISIANA STREET, SUITE 625
HOUSTON, TEXAS 77002-5008
713-651-9944
FAX 713-651-9980

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

As independent petroleum engineers, we hereby consent to the inclusion of the information included in this Form 10-K for the year ended December 31, 2006 with respect to the oil and gas reserves of EV Energy Partners, LP. We hereby further consent to all references to our firm included in this Form 10-K and to the incorporation by reference in the Registration Statement on Forms S-8, No. 333-140205 of such information.

Cawley, Gillespie, & Associates, Inc.

By: W. Todd Brooker

Austin, Texas
March 30, 2007

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-140205 on Form S-8 of our report dated April 2, 2007, relating to (i) the consolidated financial statements of EV Energy Partners, L.P. and (ii) the combined financial statements of the Combined Predecessor Entities, appearing in this Annual Report on Form 10-K of EV Energy Partners, L.P., for the year ended December 31, 2006.

Houston, Texas
April 2, 2007

CERTIFICATIONS

I, John B. Walker, certify that:

1. I have reviewed this annual report on Form 10-K of EV Energy Partners, L.P.;

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

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

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) 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) [Intentionally omitted pursuant to SEC Release No. 34-47986];

   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.

/s/ John B. Walker

Date: March 27, 2007

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

Exhibit 31.2

CERTIFICATIONS

I, Michael E. Mercer, certify that:

1. I have reviewed this annual report on Form 10-K of EV Energy Partners, L.P.;

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) 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) [Intentionally omitted pursuant to SEC Release No. 34-47986];

   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.

/s/ Michael E. Mercer

Date: March 27, 2007

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-Q for the period ended December 31, 2006 of EV Energy, L.P. (the "Partnership") and filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, John B. Walker, President and Chief Executive Officer of EV Management, LLC, the general partner of EV Energy GP, L.P., the general partner of the Partnership, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

- the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

/s/ John B. Walker

Date: March 27, 2007

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

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the accompanying report on Form 10-Q for the period ended December 31, 2006 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.

/s/ Michael E. Mercer

Date: March 27, 2007

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.