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, 2008

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

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

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

Common Units Representing Limited Partner Interests (Title of each class)	**NASDAQ Stock Market LLC** (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, a non-accelerated filer, or a smaller reporting company. See definition of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b–2 of the Exchange Act. Check one:

Large accelerated filer ☐	Accelerated filer ☑
Non-accelerated filer ☐	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b–2 of the Exchange Act).
YES ☐ NO ☑

The aggregate market value of the common units held by non–affiliates at June 30, 2008 based on the closing price on the NASDAQ Global Market on June 30, 2008 was $335,643,089.

As of March 2, 2009, the registrant had 13,130,471 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 an oil or natural gas 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.

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

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

NYMEX. The New York Mercantile Exchange.

Oil. Crude oil and condensate.

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/forms-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 federal income tax expenses or to depreciation, depletion and amortization and discounted using an annual discount rate of 10%. Our standardized measure includes future obligations under the Texas gross margin tax, but it does not include future federal income tax expenses because we are a partnership and are not subject to federal income taxes.

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

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

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

We operate in one reportable segment engaged in the exploration, development and production of oil and natural gas properties. At December 31, 2008, our properties were located in the Appalachian Basin (primarily in Ohio and West Virginia), Michigan, the Monroe Field in Northern Louisiana, Central and East Texas (which includes the Austin Chalk area), the Permian Basin, the San Juan Basin and the Mid–Continent areas in Oklahoma, Texas, Kansas and Louisiana, and we had estimated net proved reserves of 5.9 MMBbls of oil, 266.0 Bcf of natural gas and 9.6 MMBbls of natural gas liquids, or 359.2 Bcfe, and a present value of future net pre-tax cash flows discounted at 10% of $442.9 million.

The decrease in commodity prices at December 31, 2008 compared with December 31, 2007 had a significant impact on our estimated net proved reserves at December 31, 2008. The prices used in determining our estimated net proved reserves at December 31, 2008 were $44.60 per Bbl of oil, $5.71 per MMBtu of natural gas and $25.38 per Bbl of natural gas liquids as compared with $95.95 per Bbl of oil, $6.795 per MMBtu of natural gas and $57.50 per Bbl of natural gas liquids at December 31. 2007. Had the commodity prices at December 31, 2008 been the same as those in effect at December 31, 2007, our estimated net proved reserves at December 31, 2008 would have been approximately 17% higher and the present value of future net pre-tax cash flows discounted at 10% at December 31, 2008 would have been approximately 87% higher.

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, 2008:

	Estimated Net Proved Reserves				
	Oil (MMBbls)	Natural Gas (Bcf)	Natural Gas Liquids (MMBbls)	Bcfe	PV–10 [(1)] ($ in millions)
Appalachian Basin	1.0	47.6	–	53.3	$ 88.3
Michigan	–	53.4	–	53.4	55.5
Monroe Field	–	71.5	–	71.5	64.8
Central and East Texas	2.1	16.9	1.8	40.4	65.5
Permian Basin	0.5	23.6	4.0	50.8	67.5
San Juan Basin	1.2	36.5	3.8	66.2	64.1
Mid–Continent area	1.1	16.5	–	23.6	37.2
Total	5.9	266.0	9.6	359.2	$ 442.9

(1) At December 31, 2008 our standardized measure of discounted future net cash flows as calculated in accordance with Statement of Financial Accounting Standards ("SFAS") No. 69, *Disclosures About Oil and Gas Producing Activities*, was $441.9 million. Because we are a limited partnership, we made no provision for federal income taxes in the calculation of standardized measure; however, we made a provision for future obligations under the Texas gross margin tax. The present value of future net pre–tax cash flows attributable to estimated net proved reserves, discounted at 10% per annum ("PV–10"), is a computation of the standardized measure of discounted future net cash flows on a pre tax

basis. PV–10 is computed on the same basis as standardized measure but does not include a provision for federal income taxes or the Texas gross margin tax. PV–10 may be considered a non–GAAP financial measure under the SEC's regulations. We believe PV–10 to be an important measure for evaluating the relative significance of our oil and natural gas properties. We further believe investors and creditors may utilize our PV–10 as a basis for comparison of the relative size and value of our reserves to other companies. PV–10, however, is not a substitute for the standardized measure. Our PV–10 measure and the standardized measure do not purport to present the fair value of our oil and natural gas reserves.

The table below provides a reconciliation of PV–10 to the standardized measure at December 31, 2008 (dollars in millions):

PV–10	$	442.9
Future Texas gross margin taxes, discounted at 10%		(1.0)
Standardized measure	$	441.9

Developments in 2008

In 2008, we completed the following acquisitions:

- in May, we acquired oil properties in South Central Texas (the "Charlotte acquisition") for $17.4 million;
- in August 2008, we acquired oil and natural gas properties in Michigan, Central and East Texas, the Mid-Continent area (Oklahoma, Texas Panhandle and Kansas) and Eastland County, Texas (the "August acquisitions") for $58.8 million;
- in September 2008, we issued 236,169 of our common units to acquire natural gas properties in West Virginia (the "West Virginia acquisition") from EnerVest;
- in September 2008, we acquired oil and natural gas properties in the San Juan Basin (the "San Juan acquisition") from institutional partnerships managed by EnerVest for $114.7 million in cash and 908,954 of our common units.

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 conservative levels of indebtedness to reduce risk and facilitate acquisition opportunities;
- reduce exposure to commodity price risk through hedging;
- establish an inventory of proved undeveloped reserves sufficient to mitigate production declines;
- 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 ten 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.

Our Relationship with EnerVest

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

EnerVest's principal business is to act as general partner or manager of EnerVest partnerships, 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 $3.2 billion, which includes over $700 million related to our acquisitions of oil and natural gas properties. EnerVest acts as an operator of over 12,400 oil and natural gas wells in 11 states.

EnerVest and its affiliates have a significant interest in our partnership through their 71.25% ownership of our general partner, which, in turn, owns a 2% general partner interest in us and all of our incentive distribution rights. Additionally, as of March 2, 2009, EnerVest owned an aggregate of 0.5% of our outstanding common units and 57.0% 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

At December 31, 2008, our properties were located in the Appalachian Basin (primarily in Ohio and West Virginia), Michigan, the Monroe Field in Northern Louisiana, Central and East Texas (which includes the Austin Chalk area), the Permian Basin, the San Juan Basin and the Mid–Continent areas in Oklahoma, Texas, Kansas and Louisiana.

Appalachian Basin

We acquired our Appalachian Basin properties at our formation, and we acquired additional properties in the Appalachian Basin, primarily in West Virginia, in December 2007 and September 2008. Our activities are concentrated in the Ohio and West Virginia areas of the Appalachian Basin. Our Ohio area properties are producing primarily from the Clinton formation and other Devonian age sands in 22 counties in Eastern Ohio and two counties in Western Pennsylvania. Our West Virginia area properties are producing primarily from the Balltown, Benson and Big Injun formations in 22 counties in North Central West Virginia and one county in Southwestern Pennsylvania. Our estimated net proved reserves as of December 31, 2008 were 53.3 Bcfe, 89% of which is natural gas. During the year ended December 31, 2008, we drilled ten wells, all of which were successfully completed as producers. EnerVest operated wells representing 97% of our estimated net proved reserves in this area, and we own an average 92% working interest in 1,401 gross producing wells.

Michigan

We acquired our Michigan properties in January 2007, and we acquired additional properties in Michigan in August 2008. The properties are located in the Antrim Shale reservoir in Otsego and Montmorency counties in northern Michigan. Our estimated net proved reserves as of December 31, 2008 were 53.4 Bcfe, 100% of which is natural gas. During the year ended December 31, 2008, we recompleted three wells and deepened one well, all of which were successfully completed as producers. EnerVest operated wells representing 98% of our estimated net proved reserves in this area, and we have an average 85% working interest in 373 gross producing wells.

Monroe Field

We acquired our Monroe Field properties at our formation, and we acquired additional properties in the Monroe Field in March 2007. The properties are located in three parishes in Northeast Louisiana. Our estimated net proved reserves as of December 31, 2008 were 71.5 Bcfe, 100% of which is natural gas. During the year ended December 31, 2008, we drilled six wells, one of which was successfully completed as a producer. Three of the remaining five wells are awaiting completion in 2009. EnerVest operated wells representing 100% of our estimated net proved reserves in this area, and we own an average 100% working interest in 3,957 gross producing wells.

Central and East Texas

We, along with certain institutional partnerships managed by EnerVest, acquired our Central and East Texas properties in June 2007, May 2008 and August 2008. The properties are primarily located in the Austin Chalk formation in 12 counties in Central and East Texas, as well as Atascosa and Eastland counties in Texas. Our portion of the estimated net proved reserves as of December 31, 2008 was 40.4 Bcfe, 42% of which is natural gas. During the year ended December 31, 2008, we drilled 21 wells, all of which were successfully completed as producers. EnerVest operated wells representing 89% of our estimated net proved reserves in this area, and we own an average 17% working interest in 1,693 gross producing wells.

Permian Basin

We acquired our Permian Basin properties in October 2007. The properties are primarily located in the Yates, Seven Rivers, Queen, Morrow, Clear Fork and Wichita Albany formations in four counties in New Mexico and Texas. Our estimated net proved reserves as of December 31, 2008 were 50.8 Bcfe, 47% of which is natural gas. During the year ended December 31, 2008, we drilled 14 wells, all of which were successfully completed as producers. EnerVest operated wells representing 100% of our estimated net proved reserves in this area, and we own an average 89% working interest in 158 gross producing wells.

San Juan Basin

We acquired our San Juan Basin properties in September 2008. The properties are primarily located in Rio Arriba County, New Mexico and La Plata County in Colorado. Our estimated net proved reserves as of December 31, 2008 were 66.2 Bcfe, 55% of which is natural gas. During the year ended December 31, 2008, we drilled one well, which was successfully completed as a producer. EnerVest operated wells representing 95% of our estimated net proved reserves in this area, and we own an average 87% working interest in 186 gross producing wells.

Mid–Continent Area

We acquired our Mid–Continent area properties in December 2006, August 2008 and September 2008. The properties are primarily located in 25 counties in Western Oklahoma, 15 counties in Texas, four parishes in North Louisiana and six counties in Kansas. Our estimated net proved reserves as of December 31, 2008 were 23.6 Bcfe, 70% of which is natural gas. During the year ended December 31, 2008, we drilled eight wells, all of which were successfully completed as producers. EnerVest operated wells representing 42% of our estimated net proved reserves in this area, and we own an average 24% working interest in 557 gross producing wells.

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, 2008:

Reserve Data:		
Estimated net proved reserves:		
Oil (MMBbls)		5.9
Natural gas liquids (MMBbls)		9.6
Natural gas (Bcf)		266.0
Total (Bcfe)		359.2
Proved developed (Bcfe)		340.9
Proved undeveloped (Bcfe)		18.3
Proved developed reserves as a % of total proved reserves		94.9%
Standardized measure (in millions)	$	441.9

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

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

Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. Standardized measure is the present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (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 income taxes in the calculation of standardized measure; however, we have made a provision for future obligations under the Texas gross margin tax. Standardized measure does not give effect to derivative transactions. The standardized measure shown should not be construed as the current market value of the reserves. The 10% discount factor, which is required by Financial Accounting Standards Board pronouncements, is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

Our Productive Wells

The following table sets forth information relating to the productive wells in which we owned a working interest as of December 31, 2008. 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 a given well. We compute the number of net wells we own by totaling the percentage interests we hold in all our gross wells.

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

	Gross Wells			Net Wells		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
Appalachian Basin:						
Operated	18	1,305	1,323	17	1,240	1,257
Non–operated	–	78	78	–	31	31
Michigan:						
Operated	–	347	347	–	311	311
Non–operated	–	26	26	–	8	8
Monroe Field:						
Operated	–	3,957	3,957	–	3,957	3,957
Non–operated	–	–	–	–	–	–
Central and East Texas:						
Operated	682	562	1,244	206	66	272
Non–operated	164	285	449	7	13	20
Permian Basin:						
Operated	7	144	151	7	132	139
Non–operated	1	6	7	–	2	2
San Juan Basin						
Operated	19	140	159	19	136	155
Non–operated	–	22	22	–	6	6
Mid–Continent area:						
Operated	34	82	116	25	69	94
Non–operated	212	96	308	26	17	43
Total (1)	1,137	7,050	8,187	307	5,988	6,295

(1) In addition, we own small royalty interests in over 300 wells.

Our Developed and Undeveloped Acreage

The following table sets forth information relating to our leasehold acreage as of December 31, 2008:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
Appalachian Basin	37,841	36,033	77,556	66,703
Michigan	27,457	25,822	–	–
Monroe Field (1)	6,169	6,169	172,163	147,484
Central and East Texas	861,442	104,419	44,209	4,486
Permian Basin	8,576	8,485	5,610	3,761
San Juan Basin	32,953	32,727	42,497	42,289
Mid–Continent area	63,009	39,076	254	254
Total	1,037,447	252,731	342,289	264,977

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

Substantially all of our developed and undeveloped acreage is held by production, which means that as long as our wells on the acreage continue to produce, we will continue to hold the leases.

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 the properties, we may obtain a title opinion or review previously obtained title opinions. As a result, we have obtained title opinions on a significant portion of our 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 development wells completed by us during the years ended December 31, 2008 and 2007 and the three months ended December 31, 2006 and by our predecessors during the nine months ended September 30, 2006, 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			Predecessors
	Year Ended December 31,		Three Months Ended December 31,	Nine Months Ended September 30,
	2008	2007	2006	2006
Gross wells:				
Productive	58.0	27.0	7.0	30.0
Dry	2.0	1.0	–	4.0
Total	60.0	28.0	7.0	34.0
Net wells:				
Productive	28.2	20.5	7.0	20.6
Dry	2.0	1.0	–	1.0
Total	30.2	21.5	7.0	21.6

As of December 31, 2008, we were participating in the drilling of 2 gross (0.3 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 our wells and manages the day to day operating and maintenance activities for our wells.

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

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

Principal Customers and Marketing Arrangements

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

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

In 2008, Southern Union Gas Services, Enbridge Marketing (U.S.), L.P. and CMS Energy Corporation accounted for 11%, 10% and 10%, respectively, of our consolidated oil, natural gas and natural gas liquids revenues. In 2007, Enbridge Marketing (U.S.), L.P. accounted for 15% of our consolidated oil, natural gas and natural gas liquids revenues. In 2006, Exelon Energy Company, Kastle Resources Enterprises, Inc. and Ergon Oil Purchasing, Inc. accounted for 32%, 17% and 14%, respectively, of the combined oil, natural gas and natural gas liquids revenues of us and our predecessors. We believe that the loss of a major customer would have a temporary effect on our revenues but that over time, we would be able to replace our major customers.

Competition

The oil and natural gas industry is highly competitive. We encounter strong competition from other independent operators and from major oil 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 and Michigan. As a result, we generally perform the majority of our drilling in these areas during the summer and autumn months. In addition, the Monroe Field properties in Louisiana are subject to flooding. These seasonal anomalies can pose challenges for meeting our 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 the demand for natural gas is higher in the summer and winter months. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the off–peak months. 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 that govern the protection of the environment as well as the discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- 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 increased costs for environmental compliance, such as waste handling, permitting, or cleanup for the oil and natural gas industry and could have a significant impact on our operating costs.

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

Solid and Hazardous Waste Handling

The federal Resource Conservation and Recovery Act (the “RCRA”) and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous solid waste. Although oil and natural gas waste generally is exempt from regulations as hazardous waste under RCRA, we generate waste as a routine part of our operations that may be subject to RCRA. Although a substantial amount of the 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.

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 RCRA and analogous state laws. In the future, we could be required to remediate property, including groundwater, containing or impacted by previously disposed wastes (including wastes disposed or released by prior owners or operators, or property contamination, including groundwater contamination by prior owners or operators) or to perform remedial plugging operations to prevent future or mitigate existing contamination.

Comprehensive Environmental Response, Compensation and Liability Act

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

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

Clean Water Act

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, a term broadly defined. 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. In the event of an unauthorized discharge of wastes, we may be liable for penalties and costs.

Oil Pollution Act

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

Air Emissions

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

National Environmental Policy Act

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

Climate Change Legislation

More stringent laws and regulations relating to climate change and greenhouse gases (“GHGs”) may be adopted in the future and could cause us to incur material expenses in complying with them. The U.S. Congress last session considered climate change related legislation to regulate GHG emissions that could affect our operations and our regulatory costs, as well as the value of oil and natural gas generally. Although that legislation did not pass, expectations are that Congress will continue to consider some type of climate change legislation and that EPA may consider climate change–related regulatory initiatives. As a result, there is a great deal of uncertainty as to how and when federal regulation of GHGs might take place. In addition to possible federal regulation, a number of states, individually and regionally, also are considering or have implemented GHG regulatory programs. These potential federal and state initiatives may result in so–called cap–and–trade programs, under which overall GHG emissions are limited and GHG emissions are then allocated and sold, and possibly other regulatory requirements, that could result in our incurring material expenses to comply, e.g., by being required to purchase or to surrender allowances for GHGs resulting from our operations. These regulatory initiatives also could adversely affect the marketability of the oil and natural gas we produce. The impact of such future programs cannot be predicted, but we do not expect our operations to be affected any differently than other similarly situated domestic competitors.

OSHA and Other Laws and Regulation

We are subject to the requirements of the federal Occupational Safety and Health Act (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.

We believe that we are in substantial compliance with all existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. We did not incur any material capital expenditures for remediation or pollution control activities for the years ended December 31, 2008 and 2007 and 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. Additionally, we are not aware of any environmental issues or claims that will require material capital expenditures during 2008 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.

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

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 ("FERC"). Federal and state regulations govern the price and terms for access to natural gas pipeline transportation. FERC's regulations for interstate natural gas transmission in some circumstances may also affect the intrastate transportation of natural gas. FERC regulates the rates, terms and conditions applicable to the interstate transportation of natural gas by pipelines under the Natural Gas Act, 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 rule issued February 25, 2000, concerning alternatives to its traditional cost-of-service rate-making methodology to establish the rates interstate pipelines may charge for their services. The final rule revises FERC's pricing policy and current regulatory framework to improve the efficiency of the market and further enhance competition in natural gas markets.

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

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

State Natural Gas Regulation

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

Employees

EV Management, the general partner of our general partner, has four full time employees and two executive officers who spend a significant amount of their time on our operations. At December 31, 2008, EnerVest, the sole member of EV Management, had approximately 500 full–time employees, including over 70 geologists, engineers and land professionals. To carry out our operations, EnerVest employs the people who will provide direct support to our operations. None of these employees are covered by collective bargaining agreements. We consider EV Management’s relationship with its employees to be good, and EnerVest considers its 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 SEC. These documents are also available on the SEC’s website at www.sec.gov or you may read and copy any materials that we file with the SEC at the SEC’s Public Reference Room at 100 F Street, NE, Washington DC 20549. Our website also includes our Code of Business Conduct and the charters of our Audit Committee and Compensation Committee. No information from either the SEC’s website or our website is incorporated herein by reference.

ITEM 1A. RISK FACTORS

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

Risks Related to Our Business

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

In order to make our cash distributions at our current quarterly distribution rate of $0.751 per common and subordinated unit, we will require available cash of approximately $14.0 million per quarter based on the common units, subordinated units and unvested phantom units outstanding as of March 2, 2009. We may not have sufficient available cash from operating surplus each quarter to enable us to make cash distributions at this anticipated quarterly distribution rate under our cash distribution policy. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

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

In addition, the actual amount of cash we will have available for distribution will depend on other factors, some of which are beyond our control, including:

- the amount of cash reserves established by our general partner for the proper conduct of our business and for capital expenditures to maintain our production levels over the long–term, which may be substantial;
- the cost of acquisitions;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- the timing and 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.

Oil and natural gas prices have recently declined substantially. If there is a sustained recession in the United States or globally, oil and natural gas prices may continue to fall and may become and remain depressed for a long period of time, which may adversely affect our results of operations.

The United States is currently experiencing a recession. The reduced economic activity associated with the recession has reduced the demand for, and so the prices we receive for, our oil and natural gas production. A continued sustained reduction in the prices we receive for our oil and natural gas production will have a material adverse effect on our results of operations. Because we have hedged the prices we will receive for a substantial portion of our oil and natural gas production through 2013, the effects on us of a decline in oil and natural gas prices over the near term will be mitigated.

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

Our revenue, profitability and cash flow depend upon the prices for oil and natural gas. The prices we receive for oil and natural gas production are volatile and a drop in prices can significantly affect our financial results and impede our growth, including our ability to maintain or increase our borrowing capacity, to repay current or future indebtedness and to obtain additional capital on attractive terms, all of which can affect our ability to pay distributions. Changes in oil and natural gas prices have a significant impact on the value of our reserves and on our cash flows. Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in 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;
- the value of the U.S dollar relative to the currencies of other countries;
- overall domestic and global economic conditions;
- political and economic conditions and events in foreign oil and natural gas producing countries, including embargoes, continued hostilities in the Middle East and other sustained military campaigns, conditions in South America, China and Russia, and acts of terrorism or sabotage;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations and taxation;
- the impact of energy conservation efforts;
- the proximity and capacity of natural gas pipelines and other transportation facilities to our production; and
- the price and availability of alternative fuels.

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

Our hedging transactions and cash and cash equivalents expose us to counterparty credit risk.

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

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

As of December 31, 2008, we had $41.6 million in cash and cash equivalents, including investments in money market accounts with a major financial institution. We are unable to predict sudden changes in solvency of our financial institutions. In the event of a bank failure, we could incur a significant loss.

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

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

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

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

Our acquisitions involve numerous risks, including:

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

- coordinating geographically disparate organizations, systems and facilities; and
- coordinating or consolidating corporate and administrative functions.

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

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.

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

Our credit facility contains covenants limiting our ability to make distributions, incur indebtedness, grant liens, make acquisitions, investments or dispositions and engage in transactions with affiliates, as well as containing covenants requiring us to maintain certain financial ratios and tests. In addition, the borrowing base under our facility is subject to periodic review by our lenders. Difficulties in the credit markets may cause the banks to be more restrictive when redetermining our borrowing base. Our next semi-annual scheduled borrowing base redetermination is April 1, 2009. As a result of the steep decline in oil and natural gas prices, we would expect that the borrowing base under our facility will be reduced.

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

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

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

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

The standardized measure of discounted future net cash flows of our estimated net proved reserves is not necessarily the same as the current market value of our estimated net proved reserves. We base the discounted future net cash flows from our estimated net proved reserves on 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 oil and natural gas industry in general. Any material inaccuracy in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves which could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Our acquisition and development operations will require substantial capital expenditures, which will reduce our cash available for distribution. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our production and reserves.

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

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

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

We 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.

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, we might be forced to satisfy all or a portion of our hedging obligations without the benefit of the cash flows from our sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity. Lastly, an attendant risk exists in hedging activities that the counterparty in any derivative transaction cannot or will not perform under the instrument and that we will not realize the benefit of the hedge.

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

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

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

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

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

Our business activities are subject to operational risks, including:

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

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

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

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

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

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

- the 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. More stringent laws and regulations, including any related to climate change and greenhouse gases, may be adopted in the future. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other waste products into the environment.

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

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

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

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

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

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

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

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

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

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

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

We depend upon access to the public equity markets to fund our growth strategy. Currently, stock prices are depressed and if they remain depressed for an extended period of time, our growth strategy will be adversely affected.

We are experiencing unprecedented disruption in the United States and international financial markets. Equity prices for master limited partnerships, as well as for corporate stocks, have fallen substantially recently. In addition, the current disruption in the financial markets has reduced the likelihood that we could successfully issue common units or other equity securities to fund our growth. If the disruption in the financial markets continues for a substantial period of time, our ability to fund growth will be adversely affected.

Risks Inherent in an Investment in Us

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

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

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

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

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

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

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

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

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

Neither our partnership agreement nor the omnibus agreement between 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 will receive reimbursement for the provision of various general and administrative services for our benefit. In addition, we entered into contract operating agreements with a subsidiary of EnerVest pursuant to which the subsidiary will be the contract operator of all of the wells for which we have the right to appoint an operator. Payments for these services will be substantial and will reduce the amount of cash available for distribution to unitholders. In addition, under Delaware partnership law, our general partner has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our general partner. To the extent our general partner incurs obligations on our behalf, we are obligated to reimburse or indemnify it. If we are unable or unwilling to reimburse or indemnify our general partner, our general partner may take actions to cause us to make payments of these obligations and liabilities. Any such payments could reduce the amount of cash otherwise available for distribution to our unitholders.

Our partnership agreement limits our general partner's fiduciary duties to holders of our common units 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. As of March 2, 2009, our general partner, its owners and their affiliates, and EnCap own 19.5% 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 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 and EnCap hold an aggregate of 2.2 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 as 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.

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

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

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

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

Tax Risks to Common Unitholders

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

The anticipated after–tax economic benefit of an investment in 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, to the extent they were not already doing so, several states, including Texas, have implemented or are evaluating ways to subject partnerships to entity–level taxation through the imposition of state income, franchise and other forms of taxation. For example, the Texas gross margin or franchise 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 for 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, New Mexico, Colorado, Kansas, Michigan, Ohio, West Virginia and Pennsylvania. Each of these states, other than Texas, currently imposes a personal income tax. As we make acquisitions or expand our business, we may own assets or do business in additional states that impose a personal income tax. It is your responsibility to file all United States federal, foreign, state and local tax returns.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

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ITEM 2. PROPERTIES

Information regarding our properties is contained in Item 1. Business "—Our Areas of Operation" and "—Our Oil and Natural Gas Data" 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 are traded on the NASDAQ Global Market under the symbol "EVEP." At the close of business on March 2, 2009, based upon information received from our transfer agent and brokers and nominees, we had 120 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 2008 and 2007:

	Price Range		Cash Distribution per Common Unit [(1)]
	High	Low	
2008:			
First Quarter	$ 34.45	$ 21.50	$ 0.620
Second Quarter	33.08	25.10	0.700
Third Quarter	29.20	16.73	0.750
Fourth Quarter	19.50	8.78	0.751 [(2)]
2007:			
First Quarter	$ 36.74	$ 21.25	$ 0.460
Second Quarter	40.75	34.52	0.500
Third Quarter	44.13	30.01	0.560
Fourth Quarter	39.00	30.68	0.600

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

(2) On January 28, 2009, the board of directors of EV Management declared a quarterly cash distribution for the fourth quarter of 2008 of $0.751 per unit. The distribution was paid on February 13, 2009.

Cash Distributions to Unitholders

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

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

- *less* the amount of cash reserves established by our general partner to:
  - provide for the proper conduct of our business;
  - comply with applicable law, any of our debt instruments or other agreements; or

- provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters;

- *plus,* if our general partner so determines, all or a portion of cash on hand on the date of determination of available cash for the quarter including cash from working capital borrowings.

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

Initially, our general partner was entitled to 2% of all quarterly distributions that we made prior to our liquidation. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. The general partner's initial 2% interest in these distributions will be reduced if we issue additional units in the future and our general partner does not contribute a proportionate share of capital to us to maintain its 2% general partnership interest. When we issued common units in 2007, our general partner contributed to us an amount of cash necessary to maintain its 2% interest.

Our general partner also holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 25%, of the cash we distribute from operating surplus (as defined in our partnership agreement) in excess of $0.46 per unit per quarter. The maximum distribution percentage of 25% includes distributions paid to our general partner on its 2% general partner interest and assumes that our general partner maintains its general partner interest at 2%. The maximum distribution percentage of 25% does not include any distributions that our general partner may receive on common and subordinated units that it owns. For additional information on our distributions, please see Note 11 of the Notes to Consolidated/Combined Financial Statements in Item 8. "Financial Statements and Supplementary Data."

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:

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

Technical Termination of Partnership

A sale or exchange of more than 50% of the total interests in our capital and profits occurred over the twelve months ended September 30, 2008 and resulted in our termination and immediate reconstitution as a new partnership for federal income tax purposes. This termination did not affect our classification as a partnership for federal income tax purposes or affect the nature or extent of our “qualifying income” for federal income tax purposes. The closing of our taxable years will result in us filing two tax returns (and unitholders receiving two Schedule K–1’s) for one fiscal year. We will be required to reset the depreciation schedule for depreciable assets for federal income tax purposes. This will result in a deferral of depreciation deductions allowable in computing the taxable income allocated to unitholders, which effect we do not expect to be material.

Unregistered Sales of Equity Securities

None.

Issuer Purchases of Equity Securities

None.

ITEM 6. SELECTED FINANCIAL DATA

The following table shows selected financial data of us and our predecessors for the periods and as of the dates indicated. The selected financial data for the years ended December 31, 2008 and 2007 and three months ended and as of December 31, 2006 are derived from our audited financial statements. The selected financial data for the nine months ended and as of September 30, 2006 and for the years ended and as of December 31, 2005 and 2004 are derived from the audited financial statements of our predecessors. The selected financial data should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data," both contained herein.

	Successor			Predecessors (1)		
	Year Ended December 31,		Three Months Ended December 31,	Nine Months Ended September 30,	Year Ended December 31,	
	2008 (2)	2007 (3)	2006 (4)	2006	2005 (5)	2004
Statement of Operations Data:						
Revenues:						
Oil, natural gas and natural gas liquids revenues	$ 192,757	$ 89,422	$ 5,548	$ 34,379	$ 45,148	$ 28,336
Gain (loss) on derivatives, net (6)	1,597	3,171	999	1,254	(7,194)	(1,890)
Transportation and marketing–related revenues	12,959	11,415	1,271	4,458	6,225	3,438
Total revenues	207,313	104,008	7,818	40,091	44,179	29,884
Operating costs and expenses:						
Lease operating expenses	42,681	21,515	1,493	6,085	7,236	6,615
Cost of purchased natural gas	9,849	9,830	1,153	3,860	5,660	3,003
Production taxes	9,088	3,360	109	185	292	119
Exploration expenses (7)	–	–	–	1,061	2,539	1,281
Dry hole costs (7)	–	–	–	354	530	440
Impairment of unproved oil and natural gas properties (7)	–	–	–	90	2,041	1,415
Asset retirement obligations accretion expense	1,434	814	89	129	171	160
Depreciation, depletion and amortization	38,032	19,759	1,180	4,388	4,409	4,135
General and administrative expenses	13,653	10,384	2,043	1,491	1,016	1,155
Total operating costs and expenses	114,737	65,662	6,067	17,643	23,894	18,323
Operating income	92,576	38,346	1,751	22,448	20,285	11,561
Other income (expense), net	133,144	(27,102)	1,616	(229)	(428)	12
Income before income taxes and equity in income (loss) of affiliates	225,720	11,244	3,367	22,219	19,857	11,573
Income taxes	(235)	(54)	–	(5,809)	(5,349)	(2,521)
Equity in income (loss) of affiliates	–	–	–	164	565	(621)
Net income	$ 225,485	$ 11,190	$ 3,367	$ 16,574	$ 15,073	$ 8,431
General partner's interest in net income, including incentive distribution rights	$ 54,643	$ 1,670	$ 67			
Limited partners' interest in net income	$ 170,842	$ 9,520	$ 3,300			
Net income per limited partner unit:						
Common units (basic and diluted)	$ 11.14	$ 0.74	$ 0.43			
Subordinated units (basic and diluted)	$ 11.14	$ 0.74	$ 0.43			
Cash distributions per common unit	$ 2.67	$ 1.92	$ –			
Financial Position (at end ofperiod):						
Working capital	$ 94,817	$ 16,438	$ 12,006	$ 9,190	$ (642)	$ 3,094
Total assets	979,995	607,541	132,689	95,749	77,351	58,801
Long–term debt	467,000	270,000	28,000	10,350	10,500	2,850
Owners' equity	457,484	283,030	96,253	63,240	40,910	41,215

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

(2) Includes the results of (i) the Charlotte acquisition in May 2008, (ii) the August acquisitions in August 2008, (iii) the West Virginia acquisition in September 2008 and (iv) the San Juan acquisition in September 2008.

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

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

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

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

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

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.

Acquisitions in 2008

In 2008, we completed the following acquisitions:

- in May, we acquired oil properties in South Central Texas for $17.4 million;
- in August 2008, we acquired oil and natural gas properties in Michigan, Central and East Texas, the Mid-Continent area (Oklahoma, Texas Panhandle and Kansas) and Eastland County, Texas for $58.8 million;
- in September 2008, we issued 236,169 common units to EnerVest to acquire natural gas properties in West Virginia;
- in September 2008, we acquired oil and natural gas properties in the San Juan Basin from institutional partnerships managed by EnerVest for $114.7 million in cash and 908,954 of our common units.

Our Assets

As of December 31, 2008, our properties were located in the Appalachian Basin (primarily in Ohio and West Virginia), Michigan, the Monroe Field in Northern Louisiana, Central and East Texas (which includes the Austin Chalk area), the Permian Basin, the San Juan Basin and the Mid–Continent areas in Oklahoma, Texas, Kansas and Louisiana, and we had estimated net proved reserves of 5.9 MMBbls of oil, 266.0 Bcf of natural gas and 9.6 MMBbls of natural gas liquids, or 359.2 Bcfe, and a standardized measure of $441.9 million.

Business Environment

The U.S. and other world economies are currently in a recession which could last well into 2009 and beyond. Additionally, the capital markets are experiencing significant volatility, and many financial institutions have liquidity concerns, prompting government intervention to mitigate pressure on the capital markets. The primary effects of the recession on our business are expected to be a continuation in the low prices we receive for our production, which we discuss in this section. Our primary exposure to the current crisis in the debt and equity markets includes the following,

- our revolving credit facility;
- our cash investments;
- counterparty nonperformance risks; and
- our ability to finance the replacement of our reserves and our growth by accessing the capital markets,

which we discuss under "—Liquidity and Capital Resources" below.

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. Factors affecting the price of oil include the current worldwide recession, geopolitical activities, worldwide supply disruptions, weather conditions, actions taken by the Organization of Petroleum Exporting Countries and the value of the U.S. dollar in international currency markets. Factors affecting the price of natural gas include 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.

Oil and natural gas prices have declined significantly since September 30, 2008. This has reduced, and will continue to reduce, our cash flows from operations. In order to mitigate the impact of lower oil and natural gas prices on our cash flows, 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 through 2013, we have mitigated, but not eliminated, the potential effects of changing oil and natural gas prices on our cash flows from operations for those periods. If the global recession continues, commodity prices may be depressed for an extended period of time, which could alter our acquisition and exploration plans, and adversely affect our growth strategy and ability to access additional capital in the capital markets.

The primary factors affecting our production levels are capital availability, our ability to make accretive acquisitions, the success of our drilling program and our inventory of drilling prospects. In addition, 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 our production, which may have an adverse effect on our revenues and, as a result, cash available for distribution.

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

Factors Affecting 2008 Operations

In addition, the following events impacted our business in 2008:

- Third party natural gas liquids fractionation facilities in Mt. Belvieu, TX sustained damage from Hurricane Ike, which caused a reduction in the volume of natural gas liquids that were fractionated and sold during the third and fourth quarters of 2008. In addition, these facilities underwent a mandatory five year turnaround during the fourth quarter of 2008. As of December 31, 2008, we estimate that approximately 37.7 MBbls of natural gas liquids that we produced remained in storage at Mt. Belvieu. These natural gas liquids will be fractionated and sold in the future, which we currently estimate to occur primarily during the first quarter of 2009.

- We also experienced production curtailments in the Monroe Field of approximately 3.5 Mmcf from mid–May of 2008 through mid–October of 2008. These curtailments totaled approximately 590 Mmcf of natural gas for the year. However, during this period, we were contractually entitled to receive payment from the purchaser for the amount of natural gas production curtailed, subject to the purchaser recouping such amounts out of a percentage of future production.

Critical Accounting Policies

The discussion and analysis of our financial condition and results of operations is based upon the consolidated financial statements, which have been prepared in accordance with U.S. generally accepted accounting principles. The preparation of these consolidated financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosures about contingent assets and liabilities. Certain of our accounting policies involve estimates and assumptions to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions or if different assumptions had been used. We base these estimates and assumptions on historical experience and on various other information and assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Estimates and assumptions about future events and their effects cannot be perceived with certainty and, accordingly, these estimates may change as additional information is obtained, as more experience is acquired, as our operating environment changes and as new events occur.

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

Oil and Natural Gas Properties

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

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

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

The successful efforts method of accounting can have a significant impact on the operational results reported when we are entering a new exploratory area in hopes of finding an oil and natural gas field that will be the focus of future developmental drilling activity. The initial exploratory wells may be unsuccessful and will be expensed. Seismic costs can be substantial which will result in additional 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. 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. Our independent reserve engineers prepare our reserve estimates at the end of each year.

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

Accounting for Derivatives

We use derivatives to hedge against the variability in cash flows associated with the forecasted sale of our anticipated future oil and natural gas production. We generally hedge a substantial, but varying, portion of our anticipated oil and natural gas production for the next 12 – 60 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 results of operations would potentially have been significantly different had we elected and qualified for hedge accounting on our derivatives.

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

Accounting for Asset Retirement Obligations

We have significant obligations to remove tangible equipment and facilities and restore land at the end of oil and natural gas production operations. Our removal and restoration obligations are primarily associated with 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 part 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.

Revenue Recognition

Oil, natural gas and natural gas liquids revenues are recognized when production is sold to a purchaser at fixed or determinable prices, when delivery has occurred and title has transferred and collectibility of the revenue is probable. Virtually all of our contracts' pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of oil, natural gas and natural gas liquids and prevailing supply and demand conditions, so that prices fluctuate to remain competitive with other available suppliers.

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

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

RESULTS OF OPERATIONS

	Successor		Non–GAAP Combined [1]	Successor	Predecessors [2]
	Year Ended December 31,			Three Months Ended December 31,	Nine Months Ended September 30,
	2008	2007	2006	2006	2006
Revenues:					
Oil, natural gas and natural gas liquids revenues	$ 192,757	$ 89,422	$ 39,927	$ 5,548	$ 34,379
Gain on derivatives, net	1,597	3,171	2,253	999	1,254
Transportation and marketing–related revenues	12,959	11,415	5,729	1,271	4,458
Total revenues	207,313	104,008	47,909	7,818	40,091
Operating costs and expenses:					
Lease operating expenses	42,681	21,515	7,578	1,493	6,085
Cost of purchased natural gas	9,849	9,830	5,013	1,153	3,860
Production taxes	9,088	3,360	294	109	185
Exploration expenses	–	–	1,061	–	1,061
Dry hole costs	–	–	354	–	354
Impairment of unproved oil and natural gas properties	–	–	90	–	90
Asset retirement obligations accretion expense	1,434	814	218	89	129
Depreciation, depletion and amortization	38,032	19,759	5,568	1,180	4,388
General and administrative expenses	13,653	10,384	3,534	2,043	1,491
Total operating costs and expenses	114,737	65,662	23,710	6,067	17,643
Operating income	92,576	38,346	24,199	1,751	22,448
Other income (expense), net:					
Interest expense	(16,128)	(8,009)	(707)	(134)	(573)
Gain (loss) on mark–to–market derivatives, net	148,713	(19,906)	1,719	1,719	–
Other income, net	559	813	375	31	344
Total other income (expense), net	133,144	(27,102)	1,387	1,616	(229)
Income before income taxes and equity in income of affiliates	$ 225,720	$ 11,244	$ 25,586	$ 3,367	$ 22,219
Production data:					
Oil (MBbls)	437	225	165	18	147
Natural gas liquids (MBbls)	543	199	–	–	–
Natural gas (MMcf)	14,578	9,254	3,900	625	3,275
Net production (MMcfe)	20,457	11,798	4,893	734	4,159
Average sales price per unit:					
Oil (Bbl)	$ 94.76	$ 74.42	$ 63.54	$ 56.65	$ 64.38
Natural gas liquids (Bbl)	54.75	54.18	–	–	–
Natural gas (Mcf)	8.34	6.69	7.54	7.24	7.60
Average unit cost per Mcfe:					
Production costs:					
Lease operating expenses	$ 2.09	$ 1.82	$ 1.55	$ 2.04	$ 1.46
Production taxes	0.44	0.28	0.06	0.15	0.04
Total	2.53	2.10	1.61	2.19	1.50
Depreciation, depletion andamortization	1.86	1.67	1.14	1.61	1.06
General and administrative expenses	0.67	0.88	0.72	2.78	0.36

(1) 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.

(2) The financial statements of our predecessors include substantial operations that we did not acquire. In addition,

- one of the predecessors 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 reimburse EnerVest; and
- our predecessors did not incur the additional costs of being a public company.

Year Ended December 31, 2008 Compared with the Year Ended December 31, 2007

Oil, natural gas and natural gas liquids revenues for 2008 totaled $192.8 million, an increase of $103.4 million compared with 2007. This increase was primarily the result of $93.3 million related to the oil and natural gas properties that we acquired in 2008 and 2007 and $10.1 million related to higher prices for oil, natural gas liquids and natural gas.

Transportation and marketing–related revenues for 2008 increased $1.5 million compared with 2007 primarily due an increase in the price of natural gas transported through our gathering systems in the Monroe Field.

Lease operating expenses for 2008 increased $21.2 million compared with 2007 primarily as the result of $20.4 million of lease operating expenses associated with the oil and natural gas properties that we acquired in 2008 and 2007. Lease operating expenses per Mcfe were $2.09 in 2008 compared with $1.82 in 2007. This increase is primarily the result of oil and natural gas properties that we acquired in 2008 and 2007 having lease operating expenses of $2.34 per Mcfe for 2008.

The cost of purchased natural gas for 2008 was flat compared with 2007 primarily due to an increase in the price of natural gas that we purchased and transported through our gathering systems in the Monroe Field partially offset by a decrease in the volume of natural gas transported.

Production taxes for 2008 increased $5.7 million compared with 2007 primarily as the result of $5.5 million of production taxes associated with the oil and natural gas properties that we acquired in 2008 and 2007 and $0.2 million of higher production taxes associated with our increased oil, natural gas and natural gas liquids revenues. Production taxes for 2008 were $0.44 per Mcfe compared with $0.28 per Mcfe for 2007. This increase is primarily the result of the oil and natural gas properties that we acquired in 2008 and 2007 having production taxes of $0.63 per Mcfe for 2008.

Depreciation, depletion and amortization for 2008 increased $18.3 million compared with 2007 primarily due to the oil and natural gas properties that we acquired in 2008 and 2007. Depreciation, depletion and amortization for 2008 was $1.86 per Mcfe compared with $1.67 per Mcfe for 2007. This increase is primarily due to the oil and natural gas properties that we acquired in 2008 and 2007 having depreciation, depletion and amortization of $2.10 per Mcfe for 2008.

General and administrative expenses include the costs of administrative employees and related benefits, management fees paid to EnerVest, professional fees and other costs not directly associated with field operations. General and administrative expenses for 2008 increased $3.3 million compared with 2007 primarily due to (i) an additional $2.4 million of fees paid to EnerVest under the omnibus agreement, (ii) an increase of $0.8 million in accounting and tax service costs and (iii) an overall increase in costs related to our significant growth. General and administrative expenses were $0.67 per Mcfe in 2008 compared with $0.88 per Mcfe in 2007.

Interest expense for 2008 increased $8.1 million compared with 2007 primarily due to $10.8 million of additional interest expense from the increase in borrowings outstanding under our credit facility offset by $2.7 million due to lower weighted average effective interest rates in 2008 compared with 2007.

Gain on mark–to–market derivatives, net for 2008 included (i) $13.0 million of net realized losses on our oil and natural gas derivative instruments, (ii) $1.6 million of net realized losses on our interest rate swaps and (iii) $163.3 million of net unrealized gains on the mark–to–market of derivatives. The net realized losses on our oil and natural gas derivatives were primarily incurred during the first six months of 2008 when oil and natural gas prices were rising. The net unrealized gains on our mark–to market derivatives were due to the significant decline in oil and natural gas prices at December 31, 2008 compared with December 31, 2007.

Year Ended December 31, 2007 Compared with the Year Ended December 31, 2006

Oil, natural gas and natural gas liquids revenues for 2007 totaled $89.4 million, an increase of $49.5 million compared with 2006. This increase was primarily the result of an increase of $67.6 million related to the oil and natural gas properties that we acquired in 2007 and December 2006 offset by a decrease of $18.3 million related to the oil and natural gas properties that we did not acquire from one of our predecessors.

Transportation and marketing–related revenues for 2007 increased $5.7 million compared with 2006 primarily due to $7.3 million in transportation and marketing–related revenues from the March 2007 acquisition of natural gas properties in the Monroe Field partially offset by lower volumes of natural gas transported through our gathering systems due to the permanent shut–down of a compressor in the Monroe Field in May 2007.

Lease operating expenses for 2007 increased $13.9 million compared with 2006 as the result of (i) an increase of $16.5 million related to the oil and natural gas properties that we acquired in 2007 and December 2006; (ii) a decrease of $1.8 million related to the oil and natural gas properties that we did not acquire from one of our predecessors; and (iii) a decrease of $0.8 million related to the oil and natural gas properties that we acquired at our formation. Lease operating expenses per Mcfe were $1.82 in 2007 compared with $1.55 in 2006. This increase is primarily the result of the oil and natural gas properties that we acquired in 2007 and December 2006 having lease operating expenses of $1.83 per Mcfe.

The cost of purchased natural gas for 2007 increased $4.8 million compared with 2006 primarily due to (i) an increase of $5.5 million in costs from the March 2007 acquisition of natural gas properties in the Monroe Field; (ii) a decrease of $0.4 million related to a decrease in prices for purchased natural gas; and (iii) a decrease of $0.3 million related to a 8% decrease in the volume of purchased natural gas.

Production taxes for 2007 increased $3.1 million compared with 2006 primarily as the result of $3.1 million of production taxes associated with the oil and natural gas properties that we acquired in 2007 and December 2006. Production taxes for 2006 were $0.28 per Mcfe compared with $0.06 per Mcfe for 2006. This increase is primarily the result of the oil and natural gas properties that we acquired in 2007 and December 2006 having production taxes of $0.34 per Mcfe.

Depreciation, depletion and amortization increased $13.7 million compared with 2006 primarily due to (i) an increase of $15.4 million related to the oil and natural gas properties that we acquired in the 2007 and December 2006; (ii) a decrease of $2.6 million related to the oil and natural gas properties that we did not acquire from one of our predecessors and (iii) an increase of $1.4 million related to the oil and natural gas properties that we acquired at our formation. Depreciation, depletion and amortization for 2007 was $1.63 per Mcfe compared with $1.14 per Mcfe for 2006. This increase is primarily due to the oil and natural gas properties that we acquired in 2007 and December 2006 having a depreciation, depletion and amortization rate of $1.71 per Mcfe.

General and administrative expenses for 2007 totaled $10.4 million, an increase of $6.8 million compared with 2006. General and administrative expenses were $0.88 per Mcfe in 2007 compared with $0.72 per Mcfe in 2006. These increases are primarily the result of (i) $2.8 million of fees paid to EnerVest under the omnibus agreement, (ii) $2.5 million of compensation cost, including $1.5 million of compensation cost related to our phantom units, (iii) $0.3 million related to a write–off of spare parts inventory and other items associated with the acquisition of the assets of one of our predecessors, (iv) costs incurred to meet the reporting requirements of the Sarbanes–Oxley Act and (v) an overall increase in costs related to being a public partnership.

Interest expense for 2007 totaled $8.0 million, an increase of $7.3 million, or 1,033%, compared with 2006 primarily as a result of an increase in our long–term debt utilized to fund a portion of the 2007 acquisitions.

Gain on mark–to–market derivatives, net for 2007 included $9.0 million of realized gains and $28.9 million of unrealized losses on the mark–to–market of derivatives.

LIQUIDITY AND CAPITAL RESOURCES

Historically, our primary sources of liquidity and capital have been issuances of equity securities, borrowings under our credit facility and cash flows from operations, and our primary uses of cash have been acquisitions of oil and natural gas properties and related assets, development of our oil and natural gas properties, distributions to our partners and working capital needs. For 2009, we believe that cash on hand and net cash flows generated from operations will be adequate to fund our capital budget and satisfy our short–term liquidity needs. We may also utilize various financing sources available to us, including the issuance of equity or debt securities through public offerings or private placements, to fund our acquisitions and long–term liquidity needs. Our ability to complete future offerings of equity or debt securities and the timing of these offerings will depend upon various factors including prevailing market conditions and our financial condition.

In the past we accessed the equity markets to finance our significant acquisitions. Our common unit price, as well as the unit price of other master limited partnerships, has declined substantially over the past year. The financial markets are undergoing unprecedented disruptions, and many financial institutions have liquidity concerns prompting intervention from governments. The disruption in the financial markets has reduced our ability to access the public equity or debt markets until conditions improve dramatically. Until these conditions improve, we are unlikely to access the public equity or debt markets, which may limit our ability to pursue significant acquisitions.

Available Credit Facility

We have a $700.0 million facility that expires in October 2012. Borrowings under the facility are secured by a first priority lien on substantially all of our assets and the assets of our subsidiaries. We may use borrowings under the facility for acquiring and developing oil and natural gas properties, for working capital purposes, for general corporate purposes and for funding distributions to partners. We also may use up to $50.0 million of available borrowing capacity for letters of credit. The facility contains certain covenants which, among other things, require the maintenance of a current ratio (as defined in the facility) of greater than 1.0 and a ratio of total debt to earnings plus interest expense, taxes, depreciation, depletion and amortization expense and exploration expense of no greater than 4.0 to 1.0. As of December 31, 2008, we were in compliance with all of the facility covenants.

Borrowings under the facility may not exceed a “borrowing base” determined by the lenders based on our oil and natural gas reserves. As of December 31, 2008, the borrowing base was $525.0 million. The borrowing base is subject to scheduled redeterminations as of April 1 and October 1 of each year with an additional redetermination once per calendar year at our request or at the request of the lenders and with one calculation that may be made at our request during each calendar year in connection with material acquisitions or divestitures of properties. The borrowing base is determined by each lender based on the value of our proved oil and natural gas reserves using assumptions regarding future prices, costs and other matters that may vary by lender. As a result of the steep decline in oil and natural gas prices, we would expect that the lenders will decrease our borrowing base at the upcoming borrowing base redetermination. Should the amount of our borrowing base decrease below the amount outstanding under the facility, we would be required to repay any such deficiency in two equal installments 60 and 120 days after the borrowing base redetermination. We believe that we could repay any such deficiency through available cash, if any, the monetization of our derivative agreements, the sale of oil and natural gas properties, reductions in our capital expenditures and operating costs or reductions in our quarterly distributions.

If the disruption in the financial markets continues for an extended period of time, replacement of our facility may be more expensive. In addition, since our borrowing base is subject to periodic review by our lenders, difficulties in the credit markets may cause the banks to be more restrictive when redetermining our borrowing base.

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

At December 31, 2008, we had $467.0 million outstanding under the facility. In February 2009, we repaid $17.0 million of the amount outstanding under the facility.

Cash and Short–term Investments

Current conditions in the financial markets also elevate the concern over our cash and short–term investments. At December 31, 2008, we had $41.6 million of cash and short–term investments, which included $36.6 million of short–term investments. With regard to our short–term investments, we invest in money market accounts with a major financial institution.

Counterparty Exposure

At December 31, 2008, our open commodity derivative contracts were in a net receivable position with a fair value of $162.7 million. All of our commodity derivative contracts are with major financial institutions who are also lenders under our credit facility. Should one of these financial counterparties not perform, we may not realize the benefit of some of our derivative instruments under lower commodity prices and we could incur a loss.

Cash Flows

Cash flows provided (used) by type of activity were as follows:

	Successor			Predecessors
	Year Ended December 31,		Three Months Ended December 31,	Nine Months Ended September 30,
	2008	2007	2006	2006
Operating activities	$ 104,371	$ 56,114	$ 2,863	$ 20,114
Investing activities	(210,009)	(467,056)	(70,688)	(7,041)
Financing activities	137,046	419,287	69,700	(17,330)

Operating Activities

Cash flows from operations provided $104.4 million in 2008 compared with $56.1 million in 2007. The increase reflects our significant growth primarily as a result of our acquisitions.

Cash flows from operating activities provided $56.1 million in 2007. 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.

Investing Activities

Our principal recurring investing activity is the acquisition and development of oil and natural gas properties. During 2008, we spent $177.0 million on the acquisitions of oil and natural gas properties in 2008 and $33.0 million for the development of our oil and natural gas properties. During 2007, we spent $456.5 million on the acquisitions of oil and natural properties in 2007 and $10.5 million for the development of oil and natural gas properties. During the three months ended December 31, 2006, we spent $69.6 million for the acquisition of our predecessors the acquisition of oil and natural gas properties in December 2006 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.

Financing Activities

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

During 2007, we received net proceeds of $219.7 million from our private equity offerings in February and June 2007. From these net proceeds, we repaid $196.4 million of borrowings outstanding under our credit facility. We borrowed $438.4 million under our credit facility to finance the acquisitions of oil and natural gas properties in 2007 acquisitions. We paid $25.1 million of distributions to holders of our common and subordinated units. In addition, as we acquired certain oil and natural gas properties from institutional partnerships managed by EnerVest, we carried over the historical costs related to EnerVest's interests and applied purchase accounting to the remaining interests and recorded deemed distributions of $16.2 million related to the difference between the purchase price allocations and the amounts paid for these acquisitions.

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 acquisition of oil and natural gas properties in December 2006. 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.

Capital Requirements

In anticipation of a continued economic recession and the corresponding depressed prices for oil and natural gas, we have reduced our planned 2009 capital expenditures budget. We currently expect 2009 spending for the development of our oil and natural gas properties to be between $17.0 million and $20.0 million.

In 2009, we also currently expect to make distributions of approximately $56.2 million to our unitholders based on our current quarterly distribution rate of $0.751 per common unit, subordinated unit and unvested phantom unit outstanding.

We are actively engaged in the acquisition of oil and natural gas properties. We would expect to finance any significant acquisition of oil and natural gas properties in 2009 through the issuance of equity or debt securities.

Contractual Obligations

In the table below, we set forth our contractual cash obligations as of December 31, 2008. 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	$ 467,000	$ –	$ –	$ 467,000	$ –
Estimated interest payments [1]	83,009	22,135	44,272	16,602	–
Purchase obligation [2]	7,500	7,500	–	–	–
Total	$ 557,509	$ 29,635	$ 44,272	$ 483,602	$ –

(1) Amounts represent the expected cash payments for interest based on the debt outstanding and the weighted average effective interest rate of 4.74% as of December 31, 2008.

(2) Amounts represent payments to be made under our omnibus agreement with EnerVest based on the amount that we pay as of December 31, 2008. This amount will increase or decrease as we purchase or divest assets. While these payments will continue for periods subsequent to December 31, 2009, no amounts are shown as they cannot be quantified.

Our asset retirement obligations are not included in the table above given the uncertainty regarding the actual timing of such expenditures. The total amount of our asset retirement obligations at December 31, 2008 is $34.6 million.

Off–Balance Sheet Arrangements

As of December 31, 2008, we had no off–balance sheet arrangements.

NEW ACCOUNTING STANDARDS

In September 2006, the Financial Accounting Standards Board ("FASB") issued SFAS No. 157, *Fair Value Measurements,* to provide guidance for using fair value to measure assets and liabilities. SFAS No. 157 was to be effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years; however, in February 2008, the FASB issued FASB Staff Position FAS 157–2, *Effective Date of FASB Statement No. 157*, which delayed the effective date of SFAS No. 157 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis, for one year. We adopted SFAS No. 157 on January 1, 2008 for our financial assets and financial liabilities. We adopted SFAS No. 157 on January 1, 2009 for our nonfinancial assets and nonfinancial liabilities, and the adoption did not have a material 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 was effective for fiscal years beginning after November 15, 2007. We have elected not to apply the provisions of SFAS No. 159.

In December 2007, the FASB issued SFAS No 141 (Revised 2007), *Business Combinations* ("SFAS No. 141(R)") to significantly change the accounting for business combinations. Under SFAS No. 141(R), an acquiring entity will be required to recognize all the assets acquired and liabilities assumed in a transaction at the acquisition date fair value with limited exceptions and will change the accounting treatment for certain specific items, including:

- acquisition costs will generally be expensed as incurred;
- noncontrolling interests will be valued at fair value at the date of acquisition; and
- liabilities related to contingent consideration will be recorded at fair value at the date of acquisition and subsequently remeasured each subsequent reporting period.

SFAS No. 141(R) is effective for fiscal years beginning after December 15, 2008 and must be applied prospectively to business combinations completed on or after that date. We adopted SFAS No. 141(R) on January 1, 2009, and there was no impact on our consolidated financial statements.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements – An Amendment of ARB No. 51*, to establish new accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS No. 160 requires the recognition of a noncontrolling interest (minority interest) as equity in the consolidated financial statements and separate from the parent's equity. The amount of net income attributable to the noncontrolling interest will be included in consolidated net income on the face of the income statement. SFAS No. 160 clarifies that changes in a parent's ownership interest in a subsidiary that do not result in deconsolidation are equity transactions if the parent retains its controlling financial interest. In addition, SFAS No. 160 requires that a parent recognize a gain or loss in net income when a subsidiary is deconsolidated. SFAS No. 160 also includes expanded disclosure requirements regarding the interests of the parent and its noncontrolling interest. SFAS No. 160 is effective for fiscal years beginning after December 15, 2008. We adopted SFAS No. 160 on January 1, 2009, and there was no impact on our consolidated financial statements.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133.* SFAS No. 161 requires enhanced disclosures about an entity's derivative and hedging activities and how they affect an entity's financial position, financial performance and cash flows. SFAS No. 161 is effective for fiscal years and interim periods beginning after November 15, 2008. We adopted the disclosure requirements of SFAS No. 161 on January 1, 2009.

In March 2008, the FASB issued Emerging Issues Task Force 07-04, *Application of the Two–Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships* ("EITF 07–04"), to provide guidance as to how current period earnings should be allocated between limited partners and a general partner when the partnership agreement contains incentive distribution rights. EITF 07–04 is to be applied retrospectively for all financial statements presented and is effective for fiscal years beginning after December 15, 2008. We will adopt EITF 07–04 for the quarter ending March 31, 2009, and we have not yet determined the impact, if any, on our calculation of net income per limited partner unit.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles.* SFAS No. 162 identifies the sources for accounting principles and the framework for selecting the principles to be used in preparing financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles (GAAP) in the United States. SFAS No. 162 was effective on November 15, 2008.

In December 2008, the SEC published *Modernization of Oil and Gas Reporting*, a revision to its oil and natural gas reporting disclosures. The new disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes. The new requirements also will allow companies to disclose their probable and possible reserves to investors. In addition, the new disclosure requirements require companies to: (i) report the independence and qualifications of its reserves preparer or auditor; (ii) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserves audit; and (iii) report oil and natural gas reserves using an average price based upon the prior 12 month period rather than year end prices. The new disclosure requirements are effective for registration statements filed on or after January 1, 2010, and for annual reports on Forms 10–K and 20–F for fiscal years ending on or after December 31, 2009. We will adopt the new disclosure requirements when they become effective.

FORWARD–LOOKING STATEMENTS

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

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

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

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

- fluctuations in prices of oil and natural gas;
- the current disruptions in the financial markets;
- the severity and length of the current global economic recession;
- future capital requirements and availability of financing;
- uncertainty inherent in estimating our reserves;
- risks associated with drilling and operating wells;
- discovery, acquisition, development and replacement of oil and natural gas reserves;
- cash flows and liquidity;
- timing and amount of future production of oil and natural gas;
- availability of drilling and production equipment;
- marketing of oil and natural gas;
- developments in oil and natural gas producing countries;

- competition;
- general economic conditions;
- governmental regulations;
- receipt of amounts owed to us by purchasers of our production and counterparties to our derivative financial instrument contracts;
- hedging decisions, including whether or not to enter into derivative financial instruments;
- events similar to those of September 11, 2001;
- actions of third party co–owners of interest in properties in which we also own an interest;
- fluctuations in interest rates and the value of the U.S. dollar in international currency markets; and
- our ability to effectively integrate companies and properties that we acquire.

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

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

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 derivative agreements are recognized currently in earnings.

At December 31, 2008, the fair value associated with our derivative agreements was a net asset of $144.7 million.

Commodity Price Risk

Our major market risk exposure is to oil, natural gas and natural gas liquids 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, derivative agreements to reduce our risk of changes in the prices of oil and natural gas. Pursuant to our risk management policy, we engage in these activities as a hedging mechanism against price volatility associated with pre–existing or anticipated sales of oil and natural gas.

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As of December 31, 2008, we had entered into derivative agreements with the following terms:

Period Covered	Index	Hedged Volume per Day	Weighted Average Fixed Price	Weighted Average Floor Price	Weighted Average Ceiling Price
Oil (Bbls):					
Swaps – 2009	WTI	1,781	$ 93.10	$	$
Collar – 2009	WTI	125		62.00	73.90
Swaps – 2010	WTI	1,725	90.84		
Swaps – 2011	WTI	480	109.38		
Collar – 2011	WTI	1,100		110.00	166.45
Swaps – 2012	WTI	460	108.76		
Collar – 2012	WTI	1,000		110.00	170.85
Swap – 2013	WTI	500	72.50		
Natural Gas (MMBtu):					
Swaps – 2009	Dominion Appalachia	6,400	9.03		
Swaps – 2010	Dominion Appalachia	5,600	8.65		
Swap – 2011	Dominion Appalachia	2,500	8.69		
Collar – 2011	Dominion Appalachia	3,000		9.00	12.15
Collar – 2012	Dominion Appalachia	5,000		8.95	11.45
Swaps – 2009	NYMEX	9,000	8.05		
Collars – 2009	NYMEX	7,000		7.79	9.50
Swaps – 2010	NYMEX	13,500	8.28		
Collar – 2010	NYMEX	1,500		7.50	10.00
Swaps – 2011	NYMEX	12,500	8.53		
Swaps - 2012	NYMEX	12,500	9.01		
Swap – 2013	NYMEX	4,000	7.50		
Swaps – 2009	MICHCON_NB	5,000	8.27		
Swap – 2010	MICHCON_NB	5,000	8.34		
Collar – 2011	MICHCON_NB	4,500		8.70	11.85
Collar – 2012	MICHCON_NB	4,500		8.75	11.05
Swaps – 2009	HOUSTON SC	5,620	8.25		
Collar – 2010	HOUSTON SC	3,500		7.25	9.55
Collar - 2011	HOUSTON SC	3,500		8.25	11.65
Collar – 2012	HOUSTON SC	3,000		8.25	11.10
Swaps – 2009	EL PASO PERMIAN	3,500	7.80		
Swap – 2010	EL PASO PERMIAN	2,500	7.68		
Swap – 2011	EL PASO PERMIAN	2,500	9.30		
Swap – 2012	EL PASO PERMIAN	2,000	9.21		
Swap – 2013	EL PASO PERMIAN	3,000	6.77		
Swap – 2013	SAN JUAN BASIN	3,000	6.66		

Interest Rate Risk

Our floating rate credit facility also exposes us to risks associated with changes in interest rates and as such, future earnings are subject to change due to changes in these interest rates. As of December 31, 2008, we had entered into interest rate swaps with the following terms:

Period Covered	Notional Amount	Fixed Rate
January 2009 – July 2012	$ 35,000	4.043%
January 2009 – July 2012	40,000	4.050%
January 2009 – July 2012	70,000	4.220%
January 2009 – July 2012	20,000	4.248%
January 2009 – July 2012	35,000	4.250%

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 2008 and 2007:

	As of December 31, 2008							
	Expected Maturity Date							
	2009	**2010**	**2011**	**2012**	**2013**	**Thereafter**	**Total**	**Fair Value**
Long–term debt:								
Variable				$ 467,000			$ 467,000	$ 467,000
Average interest rate				4.74%			4.74%	

A 1% change in interest rates would result in an estimated $4.7 million change in interest expense.

	As of December 31, 2007							
	Expected Maturity Date							
	2008	**2009**	**2010**	**2011**	**2012**	**Thereafter**	**Total**	**Fair Value**
Long–term debt:								
Variable					$ 270,000		$ 270,000	$ 270,000
Average interest rate					7.16%		7.16%	

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management, including our Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over our financial reporting. Our internal control system was designed to provide reasonable assurance to our Management and Directors regarding the preparation and fair presentation of published financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management conducted an evaluation of the effectiveness of internal control over financial reporting based on the *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that EV Energy Partners, L.P.'s internal control over financial reporting was effective as of December 31, 2008.

Deloitte & Touche LLP, our independent registered public accounting firm, has issued an attestation report on the effectiveness on our internal control over financial reporting as of December 31, 2008 which is included in "Item 8. Financial Statements and Supplementary Data" contained herein.

/s/ JOHN B. WALKER

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

/s/ MICHAEL E. MERCER

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

Houston, TX
March 12, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of EV Energy Partners, L.P. and subsidiaries (the "Partnership") as of December 31, 2008 and 2007, and the related consolidated statements of operations, cash flows, and changes in owners' equity of the Partnership for the years ended December 31, 2008 and 2007 and three months ended December 31, 2006, and combined statement of operations, cash flows, and changes in owners' equity of the Combined Predecessor Entities (the "Entities") for the nine months ended September 30, 2006. We also have audited the Partnership's internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Partnership's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting.* Our responsibility is to express an opinion on these financial statements and an opinion on the Partnership's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated and combined financial statements referred to above present fairly, in all material respects, the financial position of the Partnership as of December 31, 2008 and 2007, and the results of their operations and their cash flows for the years ended December 31, 2008 and 2007 and the three months ended December 31, 2006, and combined statements of operations and their cash flows of the Entities for the nine months ended September 30, 2006 in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008 based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/DELOITTE & TOUCHE LLP
Houston, TX
March 12, 2009

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

	December 31, 2008	December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 41,628	$ 10,220
Accounts receivable:		
Oil, natural gas and natural gas liquids revenues	17,588	18,658
Related party	1,463	3,656
Other	3,278	15
Derivative asset	50,121	1,762
Prepaid expenses and other current assets	1,037	594
Total current assets	115,115	34,905
Oil and natural gas properties, net of accumulated depreciation, depletion and amortization; December 31, 2008, $69,958; December 31, 2007, $30,724	765,243	570,398
Other property, net of accumulated depreciation and amortization; December 31, 2008, $284; December 31, 2007, $239	180	225
Long–term derivative asset	96,720	–
Other assets	2,737	2,013
Total assets	$ 979,995	$ 607,541
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 14,063	$ 12,113
Deferred revenues	4,120	1,122
Derivative liability	2,115	5,232
Total current liabilities	20,298	18,467
Asset retirement obligations	33,787	19,463
Long–term debt	467,000	270,000
Other long-term liabilities	1,426	1,507
Long–term derivative liability	–	15,074
Commitments and contingencies		
Owners' equity:		
Common unitholders – 13,027,062 units and 11,839,439 units issued and outstanding as of December 31, 2008 and 2007, respectively	432,031	282,676
Subordinated unitholders – 3,100,000 units issued and outstanding as of December 31, 2008 and 2007	21,618	(5,488)
General partner interest	3,835	4,245
Accumulated other comprehensive income	–	1,597
Total owners' equity	457,484	283,030
Total liabilities and owners' equity	$ 979,995	$ 607,541

See accompanying notes to consolidated/combined financial statements.

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

	Successor			Predecessors
	Year Ended December 31,		Three Months Ended December 31,	Nine Months Ended September 30,
	2008	2007	2006	2006
		(Consolidated)		(Combined)
Revenues:				
Oil, natural gas and natural gas liquids revenues	$ 192,757	$ 89,422	$ 5,548	$ 34,379
Gain on derivatives, net	1,597	3,171	999	1,254
Transportation and marketing–related revenues	12,959	11,415	1,271	4,458
Total revenues	207,313	104,008	7,818	40,091
Operating costs and expenses:				
Lease operating expenses	42,681	21,515	1,493	6,085
Cost of purchased natural gas	9,849	9,830	1,153	3,860
Production taxes	9,088	3,360	109	185
Exploration expenses	–	–	–	1,061
Dry hole costs	–	–	–	354
Impairment of unproved oil and natural gas properties	–	–	–	90
Asset retirement obligations accretion expense	1,434	814	89	129
Depreciation, depletion and amortization	38,032	19,759	1,180	4,388
General and administrative expenses	13,653	10,384	2,043	1,491
Total operating costs and expenses	114,737	65,662	6,067	17,643
Operating income	92,576	38,346	1,751	22,448
Other income (expense), net:				
Interest expense	(16,128)	(8,009)	(134)	(573)
Gain (loss) on mark–to–market derivatives, net	148,713	(19,906)	1,719	–
Other income, net	559	813	31	344
Total other income (expense), net	133,144	(27,102)	1,616	(229)
Income before income taxes and equity in income of affiliates	225,720	11,244	3,367	22,219
Income taxes	(235)	(54)	–	(5,809)
Equity in income of affiliates	–	–	–	164
Net income	$ 225,485	$ 11,190	$ 3,367	$ 16,574
General partner’s interest in net income, including incentive distribution rights	$ 54,643	$ 1,670	$ 67	
Limited partners’ interest in net income	$ 170,842	$ 9,520	$ 3,300	
Net income per limited partner unit:				
Common units (basic and diluted)	$ 11.14	$ 0.74	$ 0.43	
Subordinated units (basic and diluted)	$ 11.14	$ 0.74	$ 0.43	
Weighted average limited partner units outstanding:				
Common units (basic and diluted)	12,240	9,815	4,495	
Subordinated units (basic and diluted)	3,100	3,100	3,100	

See accompanying notes to consolidated/combined financial statements.

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

	Successor			Predecessors
	Year Ended December 31,		Three Months Ended December 31,	Nine Months Ended September 30,
	2008	2007	2006	2006
		(Consolidated)		*(Combined)*
Cash flows from operating activities:				
Net income	$ 225,485	$ 11,190	$ 3,367	$ 16,574
Adjustments to reconcile net income to net cash flows provided by operating activities:				
Dry hole costs	–	–	–	354
Impairment of unproved oil and natural gas properties	–	–	–	90
Asset retirement obligations accretion expense	1,434	814	89	129
Depreciation, depletion and amortization	38,032	19,759	1,180	4,388
Share–based compensation cost	1,241	1,507	–	–
Amortization of deferred loan costs	370	155	22	–
Unrealized (gain) loss on mark–to–market derivatives	(164,867)	25,713	(906)	–
Benefit for deferred income taxes	–	–	–	(540)
Equity in income of affiliates, net of distributions	–	–	–	94
Changes in operating assets and liabilities:				
Accounts receivable	327	(8,926)	(2,278)	1,258
Prepaid expenses and other current assets	(151)	441	–	–
Accounts payable and accrued liabilities	(233)	4,627	1,536	(3,487)
Deferred revenues	2,998	1,122	–	
Due to affiliates	–	–	–	(2,089)
Income taxes	–	–	–	2,993
Other, net	(265)	(288)	(147)	350
Net cash flows provided by operating activities	104,371	56,114	2,863	20,114
Cash flows from investing activities:				
Acquisition of oil and natural gas properties, net of cash acquired	(176,992)	(456,513)	(69,517)	–
Development of oil and natural gas properties	(33,017)	(10,543)	(1,171)	(6,911)
Investment in equity investee	–	–	–	(130)
Net cash flows used in investing activities	(210,009)	(467,056)	(70,688)	(7,041)
Cash flows from financing activities:				
Long–term debt borrowings	197,000	438,350	28,000	–
Repayment of long–term debt borrowings	–	(196,350)	(10,350)	–
Proceeds from initial public offering	–	–	81,065	–
Proceeds from private equity offerings	–	220,000	–	–
Offering costs	–	(302)	(4,448)	–
Distribution to the Predecessors	–	–	(24,134)	–
Distributions related to acquisitions	(13,918)	(16,238)	–	–
Deferred loan costs	(1,331)	(1,046)	(433)	–
Contributions by partners	601	–	–	16,000
Distributions to partners and dividends paid	(45,306)	(25,127)	–	(33,330)
Net cash flows provided by (used in) financing activities	137,046	419,287	69,700	(17,330)
Increase (decrease) in cash and cash equivalents	31,408	8,345	1,875	(4,257)
Cash and cash equivalents – beginning of period	10,220	1,875	–	7,159
Cash and cash equivalents – end of period	$ 41,628	$ 10,220	$ 1,875	$ 2,902

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
Predecessors *(Combined)*:			
Balance, January 1, 2006	$ 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

	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
Proceeds from private equity offerings	215,600	–	4,400	–	220,000
Offering costs	(302)	–	–	–	(302)
Distributions in conjunction with acquisitions	(695)	(12,734)	(2,809)	–	(16,238)
Distributions	(18,226)	(5,952)	(949)	–	(25,127)
Acquisition of derivative instruments	–	–	–	425	425
Comprehensive income:					
Net income	8,598	2,368	224		
Reclassification adjustment into earnings	–	–		(3,171)	
Total comprehensive income					8,019
Balance, December 31, 2007	282,676	(5,488)	4,245	1,597	283,030
Conversion of 42,500 vested phantom units	1,262	–	–	–	1,262
Contribution from general partner	–	–	601	–	601
Issuance of 1,145,123 common units in conjunction with acquisition of oil and natural gas properties	7,927	–	–	–	7,927
Distributions in conjunction with acquisitions	(5,453)	(7,390)	(1,075)	–	(13,918)
Distributions	(32,582)	(8,278)	(4,446)	–	(45,306)
Comprehensive income:					
Net income	178,201	42,774	4,510	–	
Reclassification adjustment into earnings	–	–	–	(1,597)	
Total comprehensive income					223,888
Balance, December 31, 2008	$ 432,031	$ 21,618	$ 3,835	$ –	$ 457,484

See accompanying notes to consolidated/combined financial statements.

EV Energy Partners, L.P.
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, 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.

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") for periods beginning October 1, 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 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.

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.

EV Energy Partners, L.P.
Notes to Consolidated/Combined Financial Statements (continued)

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, 2008 and 2007, we did not have any reserves for doubtful accounts, and we did not incur any expense related to bad debts. We do not have any off–balance sheet credit exposure related to our customers.

Property and Depreciation

Our oil and natural gas producing activities are accounted for under the successful efforts method of accounting. Under this method, exploration costs, other than the costs of drilling exploratory wells, are charged to expense as incurred. Costs that are associated with the drilling of successful exploration wells are capitalized if proved reserves are found. Lease acquisition costs are capitalized when incurred. Capitalized costs associated with unproved properties totaled $0.2 million and $0.6 million as of December 31, 2008 and December 31, 2007, 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 total net proved oil and natural gas reserves as estimated by independent petroleum engineers. Proved developed reserves are used in computing unit rates for drilling and development costs and total proved reserves are used for depletion rates of leasehold, platform, and pipeline costs.

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

Impairment of Long–Lived Assets

We evaluate our proved oil and natural gas properties and related equipment and facilities for impairment whenever events or changes in circumstances indicate that the carrying amounts of such properties may not be recoverable. The determination of recoverability is made based upon estimated undiscounted future net cash flows. The amount of impairment loss, if any, is determined by comparing the fair value, as determined by a discounted cash flow analysis, with the carrying value of the related asset. For the years ended December 31, 2008, 2007 and 2006, neither we nor the Predecessors recorded any impairments related to 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 years ended December 31, 2008 and 2007 and the three months ended December 31, 2006, we recorded no impairments related to unproved oil and natural gas properties. For the nine months ended September 30, 2006, the Predecessors recorded $0.1 million of impairments related to unproved oil and natural gas properties.

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.

EV Energy Partners, L.P.
Notes to Consolidated/Combined Financial Statements (continued)

Revenue Recognition

Oil, natural gas and natural gas liquids revenues are recognized when production is sold to a purchaser at fixed or determinable prices, when delivery has occurred and title has transferred and collectibility of the revenue is probable. 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, 2008 or 2007.

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

Income Taxes

We are a partnership that is not taxable for federal income tax purposes. As such, we do not directly pay federal income tax. As appropriate, our taxable income or loss is includable in the federal income tax returns of our partners. We record our obligations under the Texas gross margin tax as “Income taxes” in our consolidated statement of operations.

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”). The computation of net income per limited partner unit is based on the weighted average number of common and subordinated units outstanding during the period. Basic and diluted net income per limited partner unit are 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.

EITF 03–06 provides that in any accounting period where our aggregate net income exceeds our aggregate distribution for such period, we are required to present net income per limited partner unit as if all of the earnings for the periods were distributed, regardless of whether those earnings would have actually been distributed. EITF 03–06 does not impact our overall net income or other financial results; however, for periods in which our aggregate net income exceeds our aggregate distributions for such period, it will have the impact of reducing the earnings per limited partner unit. This result occurs as a larger portion of our aggregate earnings is allocated to the incentive distribution rights held by EV Energy GP, as if distributed, even though we make cash distributions on the basis of cash available for distributions, not earnings, in any given accounting period. In accounting periods where aggregate net income does not exceed aggregate distributions for such period, EITF 03–06 does not have an impact on our net income per limited partner unit calculation.

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.

EV Energy Partners, L.P.
Notes to Consolidated/Combined Financial Statements (continued)

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 ("AOCI"). Amounts in AOCI 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 AOCI 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 AOCI at that date related to derivatives that previously were designated and accounted for as cash flow hedges continued to be deferred until the underlying production was produced and sold, at which time the amounts were reclassified from AOCI and reflected as a component of revenues. Changes in the fair value of derivatives that existed at October 1, 2006 and any derivatives entered thereafter are no longer deferred in AOCI, but rather are recorded immediately to net income as "Gain (loss) on mark–to–market derivatives, net" in our consolidated statement of operations.

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

Business Segment Reporting

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

Concentration of Credit Risk

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

In 2008, three customers accounted for 11%, 10% and 10%, respectively, of our consolidated oil, natural gas and natural gas liquids revenues. In 2007, one customer accounted for 15% of our consolidated oil, natural gas and natural gas liquids revenues. In 2006, three customers accounted for 32%, 17% and 14%, respectively, of the combined oil, natural gas and natural gas liquids revenues of us and our predecessors. We believe that the loss of a major customer would have a temporary effect on our revenues but that over time, we would be able to replace our major customers.

New Accounting Standards

In September 2006, the Financial Accounting Standards Board ("FASB") issued SFAS No. 157, *Fair Value Measurements,* to provide guidance for using fair value to measure assets and liabilities. SFAS No. 157 was to be effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years; however, in February 2008, the FASB issued FASB Staff Position FAS 157–2, *Effective Date of FASB Statement No. 157*, which delayed the effective date of SFAS No. 157 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis, for one year. We adopted SFAS No. 157 on January 1, 2008 for our financial assets and financial liabilities (see Note 6). We adopted SFAS No. 157 on January 1, 2009 for our nonfinancial assets and nonfinancial liabilities, and the adoption did not have a material 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 was effective for fiscal years beginning after November 15, 2007. We have elected not to apply the provisions of SFAS No. 159.

In December 2007, the FASB issued SFAS No 141 (Revised 2007), *Business Combinations* ("SFAS No. 141(R)") to significantly change the accounting for business combinations. Under SFAS No. 141(R), an acquiring entity will be required to recognize all the assets acquired and liabilities assumed in a transaction at the acquisition date fair value with limited exceptions and will change the accounting treatment for certain specific items, including:

- acquisition costs will generally be expensed as incurred;
- noncontrolling interests will be valued at fair value at the date of acquisition; and
- liabilities related to contingent consideration will be recorded at fair value at the date of acquisition and subsequently remeasured each subsequent reporting period.

SFAS No. 141(R) is effective for fiscal years beginning after December 15, 2008 and must be applied prospectively to business combinations completed on or after that date. We adopted SFAS No. 141(R) on January 1, 2009, and there was no impact on our consolidated financial statements.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements – An Amendment of ARB No. 51*, to establish new accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS No. 160 requires the recognition of a noncontrolling interest (minority interest) as equity in the consolidated financial statements and separate from the parent's equity. The amount of net income attributable to the noncontrolling interest will be included in consolidated net income on the face of the income statement. SFAS No. 160 clarifies that changes in a parent's ownership interest in a subsidiary that do not result in deconsolidation are equity transactions if the parent retains its controlling financial interest. In addition, SFAS No. 160 requires that a parent recognize a gain or loss in net income when a subsidiary is deconsolidated. SFAS No. 160 also includes expanded disclosure requirements regarding the interests of the parent and its noncontrolling interest. SFAS No. 160 is effective for fiscal years beginning after December 15, 2008. We adopted SFAS No. 160 on January 1, 2009, and there was no impact on our consolidated financial statements.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133.* SFAS No. 161 requires enhanced disclosures about an entity's derivative and hedging activities and how they affect an entity's financial position, financial performance and cash flows. SFAS No. 161 is effective for fiscal years and interim periods beginning after November 15, 2008. We adopted the disclosure requirements of SFAS No. 161 on January 1, 2009.

In March 2008, the FASB issued Emerging Issues Task Force 07-04, *Application of the Two–Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships* ("EITF 07–04"), to provide guidance as to how current period earnings should be allocated between limited partners and a general partner when the partnership agreement contains incentive distribution rights. EITF 07–04 is to be applied retrospectively for all financial statements presented and is effective for fiscal years beginning after December 15, 2008. We will adopt EITF 07–04 for the quarter ending March 31, 2009, and we have not yet determined the impact, if any, on our calculation of net income per limited partner unit.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles.* SFAS No. 162 identifies the sources for accounting principles and the framework for selecting the principles to be used in preparing financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles (GAAP) in the United States. SFAS No. 162 was effective on November 15, 2008.

In December 2008, the SEC published *Modernization of Oil and Gas Reporting*, a revision to its oil and natural gas reporting disclosures. The new disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes. The new requirements also will allow companies to disclose their probable and possible reserves to investors. In addition, the new disclosure requirements require companies to: (i) report the independence and qualifications of its reserves preparer or auditor; (ii) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserves audit; and (iii) report oil and natural gas reserves using an average price based upon the prior 12 month period rather than year end prices. The new disclosure requirements are effective for registration statements filed on or after January 1, 2010, and for annual reports on Forms 10–K and 20–F for fiscal years ending on or after December 31, 2009. We will adopt the new disclosure requirements when they become effective.

Reclassifications

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

NOTE 3. SHARE–BASED COMPENSATION

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

We account for our share–based compensation in accordance with SFAS No. 123 – Revised 2004, *Share–Based Payment* ("SFAS 123(R)"). As of December 31, 2008, we had 0.4 million phantom units outstanding, which are subject to graded vesting over a two to four year period. On satisfaction of the vesting requirement, the holders of the phantom units are entitled, at our discretion, to either common units or a cash payment equal to the current value of the units. We account for these phantom units as liability awards, and the fair value of the phantom units is remeasured at the end of each reporting period based on the current market price of our common units until settlement. Prior to settlement, compensation cost is recognized for the phantom units based on the proportionate amount of the requisite service period that has been rendered to date.

During the years ended December 31, 2008 and 2007, we recognized compensation cost of $1.2 million and $1.5 million, respectively, related to our phantom units. This cost is included in "General and administrative expenses" in our consolidated statement of operations. As of December 31, 2008, there was $4.3 million of total unrecognized compensation cost related to unvested phantom units which is expected to be recognized over a weighted average period of 3.2 years.

In January 2008, 42,500 phantom units vested and were converted to common units at a fair value of $1.3 million.

NOTE 4. ACQUISITIONS

In May 2008, we acquired oil properties in South Central Texas for $17.4 million, and in August 2008, we acquired oil and natural gas properties in Michigan, Central and East Texas, the Mid-Continent area (Oklahoma, Texas Panhandle and Kansas) and Eastland County, Texas for $58.8 million. These acquisitions were primarily funded with borrowings under our credit facility.

In September 2008, we issued 236,169 common units to EnerVest to acquire natural gas properties in West Virginia. EnerVest and its affiliates have a significant interest in our partnership through their 71.25% ownership of EV Energy GP which, in turn, owns a 2% general partner interest in us and all of our incentive distribution rights. As we acquired these natural gas properties from EnerVest, we carried over the historical costs related to EnerVest's interest and assigned a value of $5.8 million to the common units.

In September 2008, we also acquired oil and natural gas properties in the San Juan Basin (the "San Juan acquisition") from institutional partnerships managed by EnerVest for $114.7 million in cash and 908,954 of our common units. As we acquired these oil and natural gas properties from institutional partnerships managed by EnerVest, we carried over the historical costs related to EnerVest's interests in the institutional partnerships and assigned a value of $2.1 million to the common units. We then applied purchase accounting to the remaining interests acquired. As a result, we recorded a deemed distribution of $13.9 million that represents the difference between the purchase price allocation and the amount paid for the acquisitions. We allocated this deemed distribution to the common unitholders, subordinated unitholders and

EV Energy Partners, L.P.
Notes to Consolidated/Combined Financial Statements (continued)

the general partner interest based on EnerVest's relative ownership interests. Accordingly, $5.4 million, $7.4 million and $1.1 million was allocated to the common unitholders, subordinated unitholders and the general partner, respectively.

The allocation of the purchase price to the assets acquired and liabilities assumed at the date of acquisition was as follows:

	San Juan
Oil and natural gas properties	$ 105,770
Asset retirement obligations	(2,858)
Allocation of purchase price	$ 102,912

In 2007, we completed the following acquisitions:

- in January, we acquired natural gas properties in Michigan from an institutional partnership managed by EnerVest for $69.5 million, net of cash acquired;
- in March, we acquired additional natural gas properties in the Monroe Field in Louisiana from an institutional partnership managed by EnerVest for $95.4 million;
- in June, we acquired oil and natural gas properties in Central and East Texas from Anadarko Petroleum Corporation for $93.6 million;
- in October, we acquired oil and natural gas properties in the Permian Basin from Plantation Operating, LLC, a company sponsored by investment funds formed by EnCap Investments, L.P. for $154.7 million; and
- in December, we acquired oil and natural gas properties in the Appalachian Basin from an institutional partnership managed by EnerVest for $59.6 million.

The following table reflects unaudited pro forma revenues, net income and net income per limited partner unit as if the San Juan acquisition and the acquisitions completed in 2007 had taken place at the beginning of the period presented. These unaudited pro forma amounts do not purport to be indicative of the results that would have actually been obtained during the periods presented or that may be obtained in the future.

	Year Ended December 31,	
	2008	2007
Revenues	$ 231,322	$ 190,456
Net income	233,728	30,749
Net income per limited partner unit:		
Common units (basic and diluted)	$ 11.54	$ 2.03
Subordinated units (basic and diluted)	$ 11.54	$ 2.03

EV Energy Partners, L.P.
Notes to Consolidated/Combined Financial Statements (continued)

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 agreements to reduce our risk of changes in the prices of oil and natural gas. As of December 31, 2008, we had entered into derivative agreements with the following terms:

Period Covered	Index	Hedged Volume per Day	Weighted Average Fixed Price	Weighted Average Floor Price	Weighted Average Ceiling Price
Oil (Bbls):					
Swaps – 2009	WTI	1,781	$ 93.10	$	$
Collar – 2009	WTI	125		62.00	73.90
Swaps – 2010	WTI	1,725	90.84		
Swaps – 2011	WTI	480	109.38		
Collar – 2011	WTI	1,100		110.00	166.45
Swaps – 2012	WTI	460	108.76		
Collar – 2012	WTI	1,000		110.00	170.85
Swap – 2013	WTI	500	72.50		
Natural Gas (MMBtu):					
Swaps – 2009	Dominion Appalachia	6,400	9.03		
Swaps – 2010	Dominion Appalachia	5,600	8.65		
Swap – 2011	Dominion Appalachia	2,500	8.69		
Collar – 2011	Dominion Appalachia	3,000		9.00	12.15
Collar – 2012	Dominion Appalachia	5,000		8.95	11.45
Swaps – 2009	NYMEX	9,000	8.05		
Collars – 2009	NYMEX	7,000		7.79	9.50
Swaps – 2010	NYMEX	13,500	8.28		
Collar – 2010	NYMEX	1,500		7.50	10.00
Swaps – 2011	NYMEX	12,500	8.53		
Swaps - 2012	NYMEX	12,500	9.01		
Swap – 2013	NYMEX	4,000	7.50		
Swaps – 2009	MICHCON_NB	5,000	8.27		
Swap – 2010	MICHCON_NB	5,000	8.34		
Collar – 2011	MICHCON_NB	4,500		8.70	11.85
Collar – 2012	MICHCON_NB	4,500		8.75	11.05
Swaps – 2009	HOUSTON SC	5,620	8.25		
Collar – 2010	HOUSTON SC	3,500		7.25	9.55
Collar - 2011	HOUSTON SC	3,500		8.25	11.65
Collar – 2012	HOUSTON SC	3,000		8.25	11.10
Swaps – 2009	EL PASO PERMIAN	3,500	7.80		
Swap – 2010	EL PASO PERMIAN	2,500	7.68		
Swap – 2011	EL PASO PERMIAN	2,500	9.30		
Swap – 2012	EL PASO PERMIAN	2,000	9.21		
Swap – 2013	EL PASO PERMIAN	3,000	6.77		
Swap – 2013	SAN JUAN BASIN	3,000	6.66		

In addition, our floating rate credit facility exposes us to risks associated with changes in interest rates and as such, future earnings are subject to change due to changes in these interest rates. As of December 31, 2008, we had entered into interest rate swaps with the following terms:

Period Covered	Notional Amount	Fixed Rate
January 2009 – July 2012	$ 35,000	4.043%
January 2009 – July 2012	40,000	4.050%
January 2009 – July 2012	70,000	4.220%
January 2009 – July 2012	20,000	4.248%
January 2009 – July 2012	35,000	4.250%

EV Energy Partners, L.P.
Notes to Consolidated/Combined Financial Statements (continued)

At December 31, 2008, the fair value associated with these derivative agreements and interest rate swaps was a net asset of $144.7 million.

During the years ended December 31, 2008 and 2007 and three months ended December 31, 2006, we reclassified $1.6 million, $3.2 million and $1.0 million, respectively, from AOCI to "Gain on derivatives, net."

During the years ended December 31, 2008 and 2007 and three months ended December 31, 2006, we recorded unrealized gains (losses) of $163.3 million, $(28.9) million and $(0.1) million, respectively, on the change in fair value of our derivative instruments in "Gain (loss) on mark–to–market derivatives, net." In addition, we recorded net realized (losses) gains of $(14.6) million, $9.0 million and $1.8 million in the years ended December 31, 2008 and 2007 and the three months ended December 31, 2006, respectively, related to settlements of our derivative instruments in "Gain (loss) on mark–to–market derivatives, net."

NOTE 6. FAIR VALUE MEASUREMENTS

SFAS 157 establishes a valuation hierarchy for disclosure of the inputs to valuation used to measure fair value. This hierarchy prioritizes the inputs into the following three levels:

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities.
- Level 2 inputs are quoted prices for similar assets and liabilities in active markets or inputs that are observable for the asset or liability, either directly or indirectly through market corroboration.
- Level 3 inputs are unobservable inputs based on our own assumptions used to measure assets and liabilities at fair value.

A financial asset or liability's classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement.

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

		Fair Value Measurements at December 31, 2008 Using:		
	Total Carrying Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Derivative instruments	$ 144,726	$ –	$ 144,726	$ –

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

As the fair value of these derivative instruments is based on inputs using market prices obtained from independent brokers or determined using quantitative models that use as their basis readily observable market parameters that are actively quoted and can be validated through external sources, including third-party pricing services, brokers and market transactions, we have categorized these derivative instruments as Level 2. We value these derivative instruments based on observable market data for similar instruments. This observable data includes the forward curve for commodity prices based on quoted market prices and prospective volatility factors related to changes in the forward curves.

NOTE 7. 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.

During the years ended December 31, 2008 and 2007, we recorded provisions of $0.2 million and $0.1 million, respectively, for income taxes relating to our obligations under the Texas gross margin tax.

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
Current	$ 6,348
Deferred	(539)
Provision for income taxes	$ 5,809

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 of affiliates for the reasons set forth below:

	Nine Months Ended September 30, 2006
Income before income taxes and equity in income of affiliates	$ 22,219
Less: Income not subject to income taxes	(3,862)
Income before income taxes and equity in income of affiliates subject to income taxes	18,357
Statutory rate	35%
Income tax expense at statutory rate	6,425
Reconciling items:	
State income taxes, net of federal benefit	656
Percentage depletion in excess of basis	(1,225)
Other permanent items	(47)
Provision for income taxes	$ 5,809

NOTE 8. 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:

Balance as of December 31, 2006	$ 5,188
Liabilities incurred or assumed in acquisitions	13,579
Accretion expense	814
Revisions in estimated cash flows	14
Balance as of December 31, 2007	19,595
Liabilities incurred or assumed in acquisitions	13,098
Accretion expense	1,434
Revisions in estimated cash flows	514
Payments to settle liabilities	(26)
Balance as of December 31, 2008	$ 34,615

EV Energy Partners, L.P.
Notes to Consolidated/Combined Financial Statements (continued)

As of December 31, 2008 and December 31, 2007, $0.8 million and $0.1 million, respectively, of our ARO is classified as current and is included in “Accounts payable and accrued liabilities” on our consolidated balance sheet.

NOTE 9. LONG–TERM DEBT

As of December 31, 2008, our credit facility consists of a $700.0 million senior secured revolving credit facility that expires in October 2012. Borrowings under the facility are secured by a first priority lien on substantially all of our assets and the assets of our subsidiaries. We may use borrowings under the facility for acquiring and developing oil and natural gas properties, for working capital purposes, for general corporate purposes and for funding distributions to partners. We also may use up to $50.0 million of available borrowing capacity for letters of credit. The facility 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, 2008, 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 (weighted average effective interest rate of 4.74% and 7.16% at December 31, 2008 and 2007, respectively).

Borrowings under the facility may not exceed a “borrowing base” determined by the lenders based on our oil and natural gas reserves. As of December 31, 2008, the borrowing base was $525.0 million. The borrowing base is subject to scheduled redeterminations as of April 1 and October 1 of each year with an additional redetermination once per calendar year at our request or at the request of the lenders and with one calculation that may be made at our request during each calendar year in connection with material acquisitions or divestitures of properties.

We had $467.0 million and $270.0 million outstanding under the facility at December 31, 2008 and 2007, respectively.

NOTE 10. COMMITMENTS AND CONTINGENCIES

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

NOTE 11. 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.

In February 2007 and June 2007, we entered into Common Unit Purchase Agreements and Registration Rights Agreements for the issuance of 3.9 million common units and 3.4 million common units, respectively, to institutional investors in private placements. We received net proceeds of $219.7 million, including contributions of $4.4 million by our general partner to maintain its 2% interest in us. Proceeds from these issuances were primarily used to repay indebtedness outstanding under our credit facility.

In September 2008, we issued a total of 1,145,123 common units to EnerVest in conjunction with our acquisition of natural gas properties in West Virginia and oil and natural gas properties in the San Juan Basin (see Note 4).

Units Outstanding

At December 31, 2008, owner’s equity consists of 13,027,062 common units outstanding (including 737,785 common units held by affiliates of EV Management, including executive officers), 3,100,000 subordinated units (including 1,836,596 held by affiliates of EV Management, including executive officers), collectively representing a 98% limited partnership interest in us, and a 2% general partnership interest.

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Notes to Consolidated/Combined Financial Statements (continued)

Common Units

During the subordination period, the common units will have the right to receive distributions of available cash from operating surplus (as defined in our partnership agreement) 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, 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.

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.

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 laws, any of our debt instruments, or other agreements or to provide funds for distributions to unitholders and to our general partner for any one or more of the next four quarters; plus all cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter. Working capital borrowings are generally borrowings that are made under our credit facility and in all cases are used solely for working capital purposes or to pay distributions to partners.

Our partnership agreement requires that we make distributions of available cash from operating surplus 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.

EV Energy Partners, L.P.
Notes to Consolidated/Combined Financial Statements (continued)

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%

The following sets forth the distributions we paid during the years ended December 31, 2008 and 2007:

Date Paid	Period Covered	Distribution per Unit	Total Distribution
February 14, 2008	October 1, 2007 – December 31, 2007	$ 0.60	$ 9,735
May 15, 2008	January 1, 2008 – March 31, 2008	0.62	10,135
August 14, 2008	April 1, 2008 – June 30, 2008	0.70	11,732
November 14, 2008	July 1, 2008 – September 30, 2008	0.75	13,704
			$ 45,306
February 14, 2007	October 1, 2006 – December 31, 2006	$ 0.40	$ 3,100
May 15, 2007	January 1, 2007 – March 31, 2007	0.46	5,413
August 14, 2007	April 1, 2007 – June 30, 2007	0.50	7,713
November 14, 2007	July 1, 2007 – September 30, 2007	0.56	8,901
			$ 25,127

On January 28, 2009, the board of directors of EV Management declared a $0.751 per unit distribution for the fourth quarter of 2008 on all common and subordinated units. The distribution was paid on February 13, 2009 to unitholders of record at the close of business on February 6, 2009. The aggregate amount of the distribution was $13.8 million.

NOTE 12. NET INCOME PER LIMITED PARTNER UNIT

The following sets forth the net income allocation in accordance with EITF 03–06:

	Successor		
	Year Ended December 31,		October 1, 2006 through December 31,
	2008	2007	2006
Net income	$ 225,485	$ 11,190	$ 3,367
Less:			
General partner incentive distribution rights	(50,133)	(1,476)	–
General partner's 2% interest in net income	(4,510)	(194)	(67)
Net income available for limited partners	$ 170,842	$ 9,520	$ 3,300
Weighted average common units outstanding (basic and diluted)			
Common units (basic and diluted)	12,240	9,815	4,495
Subordinated units (basic and diluted)	3,100	3,100	3,100
Net income per limited partner unit (basic and diluted)	$ 11.14	$ 0.74	$ 0.43

EV Energy Partners, L.P.
Notes to Consolidated/Combined Financial Statements (continued)

NOTE 13. RELATED PARTY TRANSACTIONS

Successor

Pursuant to the Omnibus Agreement, we paid EnerVest $5.5 million, $3.1 million and $0.3 million in the years ended December 31, 2008 and 2007 and the three months ended December 31, 2006, respectively, in monthly administrative fees for providing us general and administrative services. These fees are based on an allocation of charges between EnerVest and us based on the estimated use of such services by each party, and we believe that the allocation method employed by EnerVest is reasonable and reflective of the estimated level of costs we would have incurred on a standalone basis. These fees are included in general and administrative expenses in our consolidated statement of operations.

In September 2008, we issued 236,169 common units to EnerVest to acquire natural gas properties in West Virginia. In September 2008, we also acquired oil and natural gas properties in the San Juan Basin from institutional partnerships managed by EnerVest for $114.7 million in cash and 908,954 of our common units (see Note 4).

On January 31, 2007, we acquired natural gas properties in Michigan for $69.5 million, net of cash acquired, from certain institutional partnerships managed by EnerVest, on March 30, 2007, we acquired additional natural gas properties in the Monroe Field in Louisiana from an institutional partnership managed by EnerVest for $95.4 million and on December 21, 2007, we acquired additional oil and natural gas properties in the Appalachian Basin for $59.6 million from an institutional partnership managed by EnerVest. On October 1, 2007, we acquired oil and natural gas properties in the Permian Basin in New Mexico and Texas from Plantation Operating, LLC, an EnCap sponsored company, for $154.4 million (see Note 4).

We have entered into operating agreements with EnerVest whereby a subsidiary of EnerVest acts as contract operator of the oil and natural gas wells and related gathering systems and production facilities in which we own an interest. During the years ended December 31, 2008 and 2007 and the three months ended December 31, 2006, we reimbursed EnerVest approximately $8.9 million, $6.1 million and $0.6 million, respectively, for direct expenses incurred in the operation of our wells and related gathering systems and production facilities and for the allocable share of the costs of EnerVest employees who performed services on our properties. As the vast majority of such expenses are charged to us on an actual basis (i.e., no mark–up or subsidy is charged or received by EnerVest), we believe that the aforementioned services were provided to us at fair and reasonable rates relative to the prevailing market and are representative of what the amounts would have been on a standalone basis. These costs are included in lease operating expenses in our consolidated 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.

During the three months ended March 31, 2007 and 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. On March 30, 2007, we acquired EnerVest Monroe Marketing in our acquisition of natural gas properties in the Monroe Field in Louisiana (see Note 4).

Predecessors

Pursuant to terms of certain agreements, the Predecessors paid $42,000 to EnerVest and its subsidiaries for management, accounting and advisory services in the nine months ended September 30, 2006. 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 in the nine months ended September 30, 2006 and these amounts are reflected in lease operating expenses within the combined statements of operations. As the vast majority of such expenses are charged to us on an actual basis (i.e., no mark–up or subsidy is charged or received by EnerVest), we believe that the aforementioned services were provided to us at fair and reasonable rates relative to the prevailing market and are representative of what the amounts would have been on a standalone basis. 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.

During the nine months ended September 30, 2006, the Predecessors sold $4.3 million 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 in the nine months ended September 30, 2006.

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;
- 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			Predecessors
	Year Ended December 31,		Three Months Ended December 31,	Nine Months Ended September 30,
	2008	2007	2006	2006
Supplemental cash flows information:				
Cash paid for interest	$ 15,822	$ 6,453	$ 16	$ 686
Cash paid for income taxes	171	–	–	3,357
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	924	1,653	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
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

EV Energy Partners, L.P.
Notes to Consolidated/Combined Financial Statements (continued)

NOTE 15. QUARTERLY DATA (UNAUDITED)

	Successor			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2008				
Revenues	$ 47,757	$ 61,049	$ 57,404	$ 41,103
Gross profit [1]	33,961	46,088	40,532	25,114
Net income (loss)	(24,672)	(99,524)	204,139	145,542
Limited partners' interest in net income (loss)	(24,179)	(97,533)	154,824	110,974
Net income (loss) per limited partner unit				
Basic	$ (1.61)	$ (6.51)	$ 10.14	$ 6.88
Diluted	$ (1.61)	$ (6,51)	$ 10.14	$ 6.88
2007				
Revenues	$ 12,007	$ 23,138	$ 29,429	$ 39,434
Gross profit [1]	8,219	14,667	19,359	27,058
Net income (loss)	(2,602)	11,957	13,735	(11,900)
Limited partners' interest in net income (loss)	(2,550)	11,718	12,014	(11,662)
Net income (loss) per limited partner unit				
Basic	$ (0.28)	$ 0.93	$ 0.80	$ (0.78)
Diluted	$ (0.28)	$ 0.93	$ 0.80	$ (0.78)

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

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

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			Predecessors
	Year Ended December 31,		Three Months Ended December 31,	Nine Months Ended September 30,
	2008	2007	2006	2006
Costs incurred in oil and natural gas producing activities:				
Acquisition of proved properties	$ 186,345	$ 456,393	$ 112,952	$ –
Acquisition of unproved properties	–	446	173	–
Development of oil and natural gas properties	33,940	12,197	1,728	7,152
Exploration costs	–	–	–	1,415
Asset retirement costs incurred and revised	13,794	13,593	712	11
Total	$ 234,079	$ 482,629	$ 115,565	$ 8,578

	December 31,	
	2008	2007
Capitalized costs related to oil and natural gas producing activities:		
Evaluated properties:		
Proved properties	$ 835,040	$ 600,503
Unproved properties	161	619
Accumulated depreciation, depletion and amortization	(69,958)	(30,724)
Net capitalized costs	$ 765,243	$ 570,398

EV Energy Partners, L.P.
Notes to Consolidated/Combined Financial Statements (continued)

NOTE 17. ESTIMATED PROVED OIL, NATURAL GAS AND NATURAL GAS LIQUIDS 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, natural gas and natural gas liquids reserves may not occur in the periods assumed, and actual prices realized and actual costs incurred may vary significantly from those used in this estimate. Proved reserves represent estimated quantities of oil, natural gas and natural gas liquids 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 our proved reserves as of December 31, 2008, 2007 and 2006 have been prepared by Cawley, Gillespie, & Associates, Inc., independent petroleum consultants.

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

	Oil (MBbls) (1)	Natural Gas (Mmcf) (2)	Natural Gas Liquids (MBbls) (1)	MMcfe (3)
Predecessors:				
Proved reserves:				
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:				
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
Reclass of natural gas liquids (4)	(18)	–	18	–
Purchase of minerals in place	2,450	207,285	8,841	275,031
Revision of previous estimates	190	571	35	1,921
Production	(225)	(9,254)	(199)	(11,798)
Extensions and discoveries	87	2,017	24	2,683
Proved reserves, December 31, 2007	4,504	250,010	8,719	329,348
Purchase of minerals in place	4,330	54,164	4,340	106,184
Revision of previous estimates	(2,568)	(25,500)	(2,919)	(58,422)
Production	(437)	(14,578)	(543)	(20,458)
Extensions and discoveries	48	1,945	52	2,545
Proved reserves, December 31, 2008	5,877	266,041	9,649	359,197
Proved developed reserves:				
December 31, 2006	1,920	45,906	–	57,425
December 31, 2007	3,714	223,000	5,434	277,888
December 31, 2008	5,666	253,088	8,966	340,883

(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.

(4) Reserves for natural gas liquids were included with oil reserves in prior years as the amounts were not material.

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

The following tables, which present a standardized measure of discounted future net cash flows and changes therein relating to estimated proved oil, natural gas and natural gas liquids reserves, 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, natural gas and natural gas liquids reserves. The following assumptions have been made:

- Future revenues were based on year end oil, natural gas and natural gas liquids 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%.
- For the nine months ended September 30, 2006, 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 EnerVest WV or EnerVest Production Partners in accordance with their standing as non taxable entities. For the years ended December 31, 2008 and 2007 and the three months ended December 31, 2006, no future federal income taxes were computed in accordance with our standing as non taxable entities. For the years ended December 31, 2008 and 2007, future obligations under the Texas gross margin tax were computed.

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

	Successor			Predecessors
	Year Ended December 31,		Three Months Ended December 31,	Nine Months Ended September 30,
	2008	2007	2006	2006
Estimated future cash inflows:				
Revenues from sales of oil, natural gas and natural gas liquids	$ 1,940,014	$ 2,541,295	$ 405,592	$ 263,003
Production costs	(918,719)	(937,764)	(165,968)	(113,414)
Development costs	(40,904)	(100,113)	(11,969)	(5,666)
Estimated future cash inflows before future income taxes	980,391	1,503,418	227,655	143,923
Future income taxes	(1,711)	(3,172)	–	(31,222)
Future net cash inflows	978,680	1,500,246	227,655	112,701
10% annual timing discount	(536,748)	(820,347)	(122,652)	(45,406)
Standardized measure of discounted future net cash flows	$ 441,932	$ 679,899	$ 105,003	$ 67,295

At December 31, 2008, as specified by the SEC, the prices for oil, natural gas and natural gas liquids used in this calculation were regional cash price quotes on the last day of the year except for volumes subject to fixed price contracts.

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The weighted average prices for the total estimated proved reserves at December 31, 2008, 2007 and 2006 were $44.60 per Bbl of oil, $5.71 per MMBtu of natural gas and $25.38 per Bbl of natural gas liquids, $95.95 per Bbl of oil, $6.795 per MMBtu of natural gas and $57.50 per Bbl of natural gas liquids and $60.85 per Bbl of oil and $5.635 per MMBtu of natural gas, respectively. We do not include our oil and natural gas derivative financial instruments, consisting of swaps and collars, in the determination of our oil, natural gas and natural gas liquids reserves.

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

Predecessors:	
Standardized measure, December 31, 2005	$ 182,409
Sales of oil, natural gas and natural gas liquids, net of production costs	(28,109)
Extensions and discoveries	6,499
Development costs incurred	7,152
Changes in estimated future development costs	2,776
Net changes in prices and production costs	(147,324)
Revisions and other	7,298
Changes in income taxes	22,913
Accretion of 10% timing discount	13,681
Standardized measure, September 30, 2006	$ 67,295
Successor:	
Standardized measure, September 30, 2006	$ –
Sales of oil, natural gas and natural gas liquids, net of production costs	(3,946)
Purchase of minerals in place	84,265
Extensions and discoveries	1,638
Development costs incurred	10
Changes in estimated future development costs	(7,372)
Net changes in prices and production costs	22,300
Revisions and other	6,574
Accretion of 10% timing discount	1,534
Standardized measure, December 31, 2006	105,003
Sales of oil, natural gas and natural gas liquids, net of production costs	(67,774)
Purchase of minerals in place	519,578
Extensions and discoveries	7,000
Development costs incurred	12,528
Changes in estimated future development costs	(4,092)
Net changes in prices and production costs	55,419
Revisions and other	19,176
Changes in income taxes	(1,882)
Accretion of 10% timing discount	34,943
Standardized measure, December 31, 2007	679,899
Sales of oil, natural gas and natural gas liquids, net of production costs	(131,139)
Purchase of minerals in place	249,945
Extensions and discoveries	4,543
Development costs incurred	33,940
Changes in estimated future development costs	19,720
Net changes in prices and production costs	(408,456)
Net changes in previous quantity estimates	(75,040)
Changes in timing and other	(11,354)
Changes in income taxes	2,212
Accretion of 10% timing discount	77,662
Standardized measure, December 31, 2008	$ 441,932

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

In accordance with Exchange Act Rule 13a–15 and 15d–15, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2008 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms. Our disclosure controls and procedures include controls and procedures designed to provide reasonable assurance that information required to be disclosed in reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

Pursuant to Section 404 of the Sarbanes–Oxley Act of 2002, our management included a report of their assessment of the design and effectiveness of our internal controls over financial reporting as part of this Annual Report on Form 10–K for the fiscal year ended December 31, 2008. Deloitte & Touche LLP, our independent registered public accounting firm, has issued an attestation report on the effectiveness of our internal control over financial reporting. Management's report and the independent registered public accounting firm's attestation report are included in Item 8 under the caption entitled "Management's Report on Internal Control Over Financial Reporting" and "Report of Independent Registered Public Accounting Firm" and are incorporated herein by reference.

Change in Internal Controls Over Financial Reporting

There have not been any changes in our internal controls over financial reporting that occurred during the quarterly period ended December 31, 2008 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

As is the case with many publicly traded partnerships, we do not directly employ officers, directors or employees. Our operations and activities are managed by 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 Messrs. Walker, Houser and Dwyer, are employees of EV Management and devote all of their time to our business and affairs. We estimate that Mr. Walker devotes approximately 25% of his time to our business, Mr. Houser devotes approximately 40% of his time to our business and Mr. Dwyer devotes approximately 30% of his time to our business. The officers of EV Management will manage the day–to–day affairs of our business. We also utilize a significant number of employees of EnerVest to operate our properties and provide us with certain general and administrative services. Under the omnibus agreement, we pay EnerVest a fee for its operational personnel who perform services for our benefit. During the year ended December 31, 2008, we paid EnerVest $5.5 million for general and administrative services, which fee will increase or decrease as we purchase or divest assets.

The following table shows information as of March 2, 2009 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	63	Chairman and Chief Executive Officer
Mark A. Houser	47	President, Chief Operating Officer and Director
Michael E. Mercer	50	Senior Vice President and Chief Financial Officer
Kathryn S. MacAskie	52	Senior Vice President of Acquisitions and Divestitures
Frederick Dwyer	49	Controller
Victor Burk (1) (2)	59	Director
James R. Larson (1)	59	Director
George Lindahl III (1) (2)	62	Director
Gary R. Petersen (2)	62	Director

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

(2) Member of the compensation committee.

John B. Walker has served as EV Management's Chairman and Chief Executive Officer since 2006. He has been the President and CEO of EnerVest, Ltd. since its formation in 1992. Prior to that, Mr. Walker was President and Chief Operating Officer of Torch Energy Advisors Incorporated, a company which formed and managed partnerships for institutional investors in the oil and natural gas business, and Chief Executive Officer of Walker Energy Partners, a master limited partnership engaged in the exploration and production business. 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 as Chairman of the Board of 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, 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 was a consultant to EnerVest, Ltd. from 2001 to 2006. Prior to that, Mr. Mercer was an investment banker for twelve years. He was a Director in the Energy Group at Credit Suisse First Boston in Houston and a Director in the Energy Group at Salomon Smith Barney in New York and London. He holds a BBA in Petroleum Land Management from the University of Texas at Austin and an MBA from the University of Chicago Graduate School of Business.

Kathryn S. MacAskie has served as our Senior Vice President of Acquisitions and Divestitures since 2006. She was President and co-owner of FlairTex Resources, Inc., a petroleum engineering consulting and acquisition business from 2002 to 2006. 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, 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. From 2001 to 2007, he was a Managing Partner for Sandefer Capital Partners. From 2000 to 2001 he served as Vice Chairman of Anadarko Petroleum Corporation. From 1987 to 2000, he was with Union Pacific Resources, serving as President and Chief Operating Officer from 1996 to 1999 and as Chairman, President and CEO from 1999 to 2000. He holds a BS in Geology from the University of Alabama and has completed the Advanced Management program at Harvard Business School.

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, Mr. Petersen, was appointed by EnCap and the remainder of which were appointed by EnerVest.

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

Unitholder Communications

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

Committees of the Board of Directors

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

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

Audit Committee

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

The audit committee assists the board of directors in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and corporate policies and controls. The audit committee has the sole authority and responsibility to retain and terminate our independent registered public accounting firm, resolve disputes with such firm, approve all auditing services and related fees and the terms thereof, and pre–approve any non–audit services to be rendered by our independent registered public accounting firm. The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm is given unrestricted access to the audit committee and meets with the audit committee on a regularly scheduled basis. During 2008, representatives of our independent auditors attended all of our audit committee meetings. The audit committee may also engage the services of advisors and accountants as it deems advisable.

Compensation Committee

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

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 conflict of interest has been resolved in accordance with our partnership agreement. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our general partner of any duties it may owe us or our unitholders.

Meetings and Other Information

During 2008, the board of directors had eight regularly scheduled and special meetings, the audit committee had four meetings, the compensation committee had one meeting and the conflicts committee had five meetings. None of our directors attended fewer than 75% of the aggregate number of meetings of the board of directors and committees of the board on which the director served.

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

Section 16(a) Beneficial Ownership Reporting Compliance

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

Based solely on a review of the copies of reports on Forms 3, 4 and 5 and amendments thereto furnished to us and written representations from the executive officers and directors of EV Management, we believe that during the year ended December 31, 2008, the officers and directors of EV Management and beneficial owners of more than 10% of our equity securities registered pursuant to Section 12 were in compliance with the applicable requirements of Section 16(a).

Code of Ethics

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

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

Audit Committee Report

REPORT OF THE AUDIT COMMITTEE FOR FISCAL YEAR 2008

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, 2008, 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 in the United States of America 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. 114 *"The Auditor's Communication With Those Charged With Goverance."* 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, 2008.

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 pay EnerVest a fee for general and administrative services undertaken for our benefit and for our allocable portion of the premiums on insurance policies covering our assets. In addition, we reimburse EV Management for the costs of employee, officer and director compensation and benefits properly allocable to us, as well as for other expenses necessary or appropriate to the conduct of our business and properly allocable to us. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

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

Messrs. Walker, Houser and Dwyer are officers of EV Management and also are officers and employees of subsidiaries of EnerVest. In these capacities, they perform services for us as well as for EnerVest and its other affiliates. Messrs. Walker, Houser and Dwyer receive their base salary and short–term and long–term incentive compensation from EnerVest. Our compensation committee discusses with EnerVest the philosophy used by EnerVest in setting their salaries and bonus compensation, but the compensation committee has no role in determining the base salary and short–term and long–term incentive compensation paid to them by EnerVest. We pay EnerVest a fee under the omnibus agreement which is based in part on the compensation paid to EnerVest employees who perform work for us, but we do not directly reimburse EnerVest for the costs of the compensation of Messrs. Walker, Houser and Dwyer. In addition to the compensation paid to them by EnerVest, Messrs. Walker, Houser and Dwyer participate in our equity incentive plan. Awards made to Messrs. Walker, Houser and Dwyer under the plan are determined by our compensation committee.

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

Objectives of Our Compensation Program

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

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

What Our Compensation Program is Designed to Reward

Our compensation program is designed to reward performance that contributes to the achievement of our business strategy on both a short–term and long–term basis. 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.

Performance Metrics

Our compensation committee did not establish performance metrics for our executive officers at the beginning of the year. Our compensation committee does not intend to establish metrics, goals and target compensation levels for 2009 to remain flexible in our compensation practices during our first several years as a public master limited partnership.

In setting 2008 bonus and long–term incentives amounts, the compensation committee considered the performance of our executive officers in causing us to achieve the following milestones in 2008:

- our quarterly distributions increased from $0.60 per unit to $0.751 per unit;
- our asset base increased over 32% from over $226 million in accretive acquisitions; and
- our operating performance was within budget.

Based on this success, our compensation committee generally awarded bonuses and long–term incentives that reflected good to excellent performance.

Elements of Our Compensation Program and Why We Pay Each Element

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

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

Base Salary

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

To provide stability as well as incentivize appropriately, Mr. Mercer and Ms. MacAskie are parties to employment agreements which set their minimum base salaries per annum. In the compensation committee’s discretion, however, these base salaries may be increased based upon performance and subjective factors. For 2008, the compensation committee increased the base salary of both Mr. Mercer and Ms. MacAskie by 2.9%, generally representing a cost of living increase. Subjective factors the compensation committee considered 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.

Cash Bonus

We include an annual cash bonus as part of our compensation program because we believe this element of compensation helps to motivate management to achieve key operational objectives by rewarding the achievement of these objectives. The annual cash bonus also allows us to be competitive from a total remuneration standpoint.

The cash bonuses paid to Mr. Mercer and Ms. MacAskie reflect the belief of our compensation committee that their efforts directly affected our success in 2008. Taking into account the achievement of the goals described above at the good or excellent level, for 2008, the compensation committee awarded both Mr. Mercer and Ms. MacAskie bonuses of $135,000 each, representing 60% of their 2008 base salaries.

In general, the compensation committee targets between 50% and 75% of base salary for performance deemed by our compensation committee to be good (to generally exceed expectations) and great (to significantly exceed expectations), respectively, with the possibility of no bonus for poor performance and higher for exceptional corporate or individual performance.

Long–term Equity–based Compensation

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

The compensation committee and/or our board of directors act as the manager of our long–term incentive plan (the "Plan") 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 plan. For compensation decisions regarding the grant of equity compensation to executive officers, our compensation committee will consider recommendations from our chief executive officer. Typically, awards vest over multiple years, but the compensation committee maintains the discretionary authority to vest the equity grant immediately if the individual situation merits. In the event of a 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.

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 1,500,000 units. As of December 31, 2008, there are 1,045,200 units available for issuance. Unless earlier terminated by us or unless all units available under the plan have been paid to participants, the Plan will terminate as of the close of business on September 20, 2016.

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

In addition, because we are a partnership, tax and accounting conventions make it more costly for us to issue additional common units or options as incentive compensation. Consequently, we have no outstanding options or restricted units and have no plans to issue options or restricted units in the future. Instead, we have issued phantom units to our executive officers that are paid by issuance of units or, at the discretion of our compensation committee, in cash based on the average closing price of our common units for the 5 day trading period prior to vesting. The phantom units typically vest two to four years from the date of grant. In connection with the phantom unit awards, the committee also grants tandem DERs, which entitle the holders to receive distributions equal to the distributions paid on our common units. Through these awards, each executive officer's interest is aligned with those of our unitholders in increasing our quarterly cash distributions, our unit price and maintaining a steady growth profile.

In 2008, Mr. Mercer and Ms. MacAskie were each granted 25,000 phantom units, taking into account their achievement of the goals described above at the good or excellent level. 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, our compensation committee takes into consideration discretionary factors such as the individual's current and expected future performance, level of responsibilities, retention considerations, and the total compensation package.

Because Messrs. Walker, Houser and Dwyer commit less than half of their business time to us, the compensation committee believes that it is appropriate to compensate them only through long–term incentives that will reward them in accordance with our long–term success. Messrs. Walker, Houser ware granted 30,000 and 27,000 phantom units, respectively, to reflect their leadership roles in causing us to reach the goals described above at the good or excellent level.

Benefits

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

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

How Elements of Our Compensation Program are Related to Each Other

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

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

Accounting and Tax Considerations

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

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

Compensation Committee Report

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

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

Summary Compensation Table

The following table sets forth certain information with respect to compensation of our named executive officers, except for Mr. Dwyer whose compensation paid by us was less than $100,000. We reimburse EV Management for the costs of Mr. Mercer's and Ms. MacAskie's salaries and bonuses. Messrs. Walker, Houser and Dwyer are compensated by EnerVest. We pay EnerVest a fee under the omnibus agreement, but we do not directly reimburse EnerVest for the costs of their salaries and bonuses.

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

Name and Principal Position	Year	Salary	Bonus (1)	Unit Awards (2)	All Other Compensation (3)	Total
John B. Walker	2008	$ –	$ –	$ 256,986	$ 115,050	$ 372,036
Chief Executive Officer	2007	–	–	308,907	75,300	384,207
	2006	–	–	450,000	–	450,000
Mark A. Houser	2008	–	–	232,751	101,700	334,451
President, Chief Operating Officer	2007	–	–	306,711	75,300	382,011
	2006	–	–	450,000	–	450,000
Michael E. Mercer	2008	223,600	135,000	173,657	117,675	649,932
Senior Vice President, Chief Financial Officer	2007	215,000	135,000	232,983	117,000	699,983
	2006	50,000	200,000	1,200,000	–	1,450,000
Kathryn S. MacAskie	2008	223,600	135,000	239,336	121,425	719,361
Senior Vice President ofAcquisitions and Divestitures	2007	215,000	135,000	383,945	113,000	846,945
	2006	43,750	100,000	1,000,000	–	1,143,750

(1) Represents amounts paid in December 2008 and 2007 as bonuses for services in 2008 and 2007, respectively.

(2) Represents the dollar amounts recognized for financial statement reporting purposes in accordance with SFAS No. 123(R) for the grants of phantom units.

(3) Represents cash distributions received on the unvested phantom units and on the unvested subordinated units held by EV Investors and paid to the named executive officer as discussed under "–EV Investors" below. Any perquisites or other personal benefits received were less than $10,000.

Narrative Disclosure to the Summary Compensation Table

Mr. Walker

Mr. Walker received a grant of 30,000 phantom units in December 2008. This grant vests 1/4 each in January 2010, January 2011, January 2012 and January 2013. Mr. Walker received grants of 20,000 phantom units and 25,000 phantom units in January 2007 and December 2007, respectively. The January 2007 grant vested 50% in January 2008 and 50% in January 2009. The December 2007 grant vested 1/3 in January 2009, with 1/3 vesting in January 2010 and 1/3 vesting in January 2011. These phantom units will vest in full upon a change of control or a termination without cause, with good reason or upon Mr. Walker's death or disability.

Mr. Houser

Mr. Houser received a grant of 27,000 phantom units in December 2008. This grant vests 1/4 each in January 2010, January 2011, January 2012 and January 2013. Mr. Houser received grants of 20,000 phantom units and 20,000 phantom units in January 2007 and December 2007, respectively. The January 2007 grant vested 50% in January 2008 and 50% in January 2009. The December 2007 grant vested 1/3 in January 2009, with 1/3 vesting in January 2010 and 1/3 vesting in January 2011. These phantom units will vest in full upon a change of control or a termination without cause, with good reason or upon Mr. Houser's death or disability.

Mr. Mercer

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, 2009, 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 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.

Mr. Mercer received a grant of 25,000 phantom units in December 2008. This grant vests 1/4 each in January 2010, January 2011, January 2012 and January 2013. Mr. Mercer received grants of 7,500 phantom units, 7,500 phantom units and 15,000 phantom units in January 2007, August 2007 and December 2007, respectively. The January 2007 and August 2007 grants vested 50% in January 2008 and 50% in January 2009. The December 2007 grant vested 1/3 in January 2009, with 1/3 vesting in January 2010 and 1/3 vesting in January 2011. These phantom units will vest in full upon a change of control or a termination without cause, with good reason or upon Mr. Mercer's death or disability.

Ms. MacAskie

EV Management entered into an employment agreement with Ms. MacAskie that provides that she will act as Senior Vice President of Acquisitions and Divestitures of EV Management until December 31, 2009, 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 Ms. MacAskie is terminated by EV Management without cause or he dies or is disabled.

Ms. MacAskie's employment agreement provides for a minimum base salary of $175,000, subject to upward adjustment by the compensation committee or EV Management's board of directors, and an annual bonus equal to a percentage of her base salary based on the achievement of performance criteria for the applicable period, all as determined by the compensation committee.

Ms. MacAskie received a grant of 25,000 phantom units in December 2008. This grant vests 1/4 each in January 2010, January 2011, January 2012 and January 2013. Ms. MacAskie received grants of 12,500 phantom units, 12,500 phantom units and 15,000 phantom units in January 2007, August 2007 and December 2007, respectively. The January 2007 and August 2007 grants vested 50% in January 2008 and 50% in January 2009. The December 2007 grant vested 1/3 in January 2009, with 1/3 vesting in January 2010 and 1/3 vesting in January 2011. These phantom units will vest in full upon a change of control or a termination without cause, with good reason or upon Ms. MacAskie's death or disability.

Grants of Plan–Based Awards

The following table sets forth certain information with respect to grants of phantom units to our named executive officers in 2008. There were no grants of non–equity incentives, equity incentives or option awards.

Name	Grant Date	All Other Unit Awards: Number of Units (1)
John B. Walker	December 2008	30,000
Mark A. Houser	December 2008	27,000
Michael E. Mercer	December 2008	25,000
Kathryn S. MacAskie	December 2008	25,000

(1) Represents the number of units granted to each named executive officer pursuant to the Plan and terms of certain executives' employment agreements.

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Outstanding Equity Awards at Fiscal Year End

The following table sets forth certain information with respect to outstanding equity awards at December 31, 2008. There were no option awards or equity incentive plan awards outstanding.

Name	Number of Units That Have Not Yet Vested	Market Value of Units That Have Not Yet Vested (1)
John B. Walker	10,000(2) 25,000(3) 30,000(4)	$ 953,550
Mark A. Houser	10,000(2) 20,000(3) 27,000(4)	836,190
Michael E. Mercer	3,750(2) 3,750(2) 15,000(3) 25,000(4)	696,825
Kathryn S. MacAskie	6,250(2) 6,250(2) 15,000(3) 25,000(4)	770,175

(1) Based on the closing price of our common units on December 31, 2008 of $14.67.

(2) These phantom units vested in January 2009.

(3) These phantom units vested 1/3 in January 2009, with 1/3 vesting in January 2010 and 1/3 vesting in January 2011.

(4) These phantom units vest 1/4 each in January 2010, January 2011, January 2012 and January 2013.

Option Exercises and Units Vested

The following table sets forth certain information with respect to phantom units vested during the year ended December 31, 2008. There were no option awards that vested.

Name	Number of Units Acquired on Vesting (#)	Value Realized on Vesting ($)
John B. Walker	10,000	$ 297,000
Mark A. Houser	10,000	297,000
Michael E. Mercer	7,500	222,750
Kathryn S. MacAskie	12,500	371,250

Pension Benefits

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

Nonqualified Deferred Compensation

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

Termination of Employment and Change–in–Control Provisions

Mr. Mercer 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, 2008. In presenting this disclosure, we describe amounts earned through December 31, 2008 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, 2008, for both Mr. Mercer and Ms. MacAskie, this amount would have been $447,200. 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, 2008, for Mr. Mercer, this amount would have been $27,924, and for Ms. MacAskie this amount would have been $18,647.

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, 2008, for Mr. Mercer, this amount would have been $447,200 representing 104 weeks of base salary, $696,825 representing vesting of unvested units, and $27,924 representing COBRA coverage. For Ms. MacAskie, this amount would have been $447,200 representing 104 weeks of base salary, $770,175 representing vesting of unvested units, and $18,647 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

The phantom unit 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. Assuming termination of employment or change of control as of December 31, 2008, for Mr. Mercer, the value of the awards would have been $696,825, and for Ms. MacAskie, the value of the awards would have been $770,175. 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.

EV Investors

When EV Properties was formed in May 2006, EV Investors was issued a limited partnership interest in one of our predecessors. 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. The predecessor 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 in September 2006, EV Investors transferred its limited partnership interest in the predecessor 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, because these limited partners did not forfeit their limited partnership interests, they had distributed to them their share of the subordinated units. The forfeiture period terminated as to half of the limited partnership interest on September 30, 2007 and the other half on September 30, 2008.

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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 receives distributions 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

Compensation of Directors

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

Directors who are not officers or employees of EV Management, EnCap or their respective affiliates receive an annual retainer of $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 receives $1,000 per committee meeting attended ($500 if by phone) and is reimbursed for his out of pocket expenses in connection with attending meetings. We indemnify each director for his actions associated with being a director to the fullest extent permitted under Delaware law.

Each of the independent directors was awarded 2,000 phantom units in December 2008. Mr. Petersen, who is not an independent director because of his affiliations with EnCap, was awarded 1,500 phantom units in December 2008. These phantom units vest 25% each on January 15, 2010, January 15, 2011, January 15, 2012 and January 15, 2013**.**

The following table discloses the cash unit awards and other compensation earned, paid or awarded to each of EV Management's directors during year ended December 31, 2008:

Name [(1)]	Fees Earned or Paid in Cash ($)	Unit Awards [(2)] ($)	All Other Compensation [(3)] ($)	Total
Victor Burk	$ 36,000	$ 19,220	$ 5,674	$ 60,894
James R. Larson	37,500	19,220	5,674	62,394
George Lindahl III	35,500	19,220	5,674	60,394
Gary R. Petersen	–	17,368	5,006	22,374

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

(2) Reflects the dollar amount recognized for financial statement reporting purposes for the year ended December 31, 2008 in accordance with SFAS No. 123(R) for the grants of phantom units.

(3) Reflects the dollar amount of compensation recognized for financial statement reporting purposes for the year ended December 31, 2008 for distributions paid on the unvested phantom units.

Compensation Committee Interlocks and Insider Participation

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

None of the members of the compensation committee have served as an officer or employee of us, our general partner or its general partner. Furthermore, except for compensation arrangements discussed in this Form 10–K, we have not participated in any contracts, loans, fees, awards or financial interests, direct or indirect, with any committee member, nor are we aware of any means, directly or indirectly, by which a committee member could receive a material benefit from us.

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

Security Ownership of Certain Beneficial Owners

Based solely on a review of the copies of reports on Schedule 13G and amendments thereto furnished to us, we believe that there were no beneficial owners of more than 5% of our common or subordinated units as of March 2, 2009.

Security Ownership of Management

The following table sets forth the beneficial ownership of our units as of March 2, 2009 held by:

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

Name of Beneficial Owner (1)	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned	Percentage of Common Units and Subordinated Units Beneficially Owned
Officers and Directors:					
John B. Walker (2)	584,364	4.5%	1,806,596	58.3%	14.7%
Mark A. Houser (3)	144,921	1.1%	45,000	1.5%	1.2%
Michael E. Mercer (4)	28,000	*	65,000	2.1%	*
Kathryn S. MacAskie (5)	43,000	*	51,000	1.6%	*
Frederick Dwyer	3,333	*	1,500	*	*
Victor Burk	4,000	*	1,000	*	*
James R. Larson	3,000	*	–	–	*
George Lindahl III	49,700	*	4,000	*	*
Gary R. Petersen (6)	25,571	*	436,170	14.1%	2.8%
All directors andexecutive officers as agroup (9 persons)	885,889	6.7%	2,277,666	73.5%	19.5%

* 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 67,923 common units and 1,611,596 subordinated units owned by EnerVest and 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 subordinated units owned by EV Investors. 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 in which he does not have a pecuniary interest.

(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 1,000 common units held by a family trust of which Ms. MacAskie is a trustee and 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 common units held by the trust and the subordinated units owned by EV Investors.

(6) Includes 14,279 common units and 243,350 subordinated units owned by EnCap Energy Capital Fund V, L.P. and 11,292 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. Jon 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, 2008:

	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	412,300	–	1,045,200
Equity compensation plans not approved by security holders	–	–	–
Total	412,300	–	1,045,200

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

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

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

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

Contracts with EnerVest and Its Affiliates

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

We have entered into agreements with EnerVest. The following is a description of 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 for providing us general and administrative and all other services with respect to our existing business and operations;
- our obligation to reimburse EnerVest for any insurance coverage expenses it incurs with respect to our business and operations; and
- EnerVest's obligation to indemnify us for certain liabilities and our obligation to indemnify EnerVest for certain liabilities.

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

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

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

During the year ended December 31, 2008, we paid EnerVest $5.5 million in monthly administrative fees under the omnibus agreement. These fees are based on an allocation of charges between EnerVest and us based on the estimated use of such services by each party, and we believe that the allocation method employed by EnerVest is reasonable and reflective of the estimated level of costs we would have incurred on a standalone basis. The initial term of the omnibus agreement expired on December 31, 2008. In December 2008, EV Management and EnerVest extended the term of the omnibus agreement through 2009.

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 year ended December 31, 2008, we reimbursed EnerVest approximately $8.9 million for direct expenses incurred in the operation of our wells and related gathering systems and production facilities and for the allocable share of the costs of EnerVest employees who performed services on our properties. As the vast majority of such expenses are charged to us on an actual basis (i.e., no mark–up or subsidy is charged or received by EnerVest), we believe that the aforementioned services were provided to us at fair and reasonable rates relative to the prevailing market and are representative of what the amounts would have been on a standalone basis.

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

In September 2008, we issued 236,169 common units to EnerVest to acquire natural gas properties in West Virginia. In September 2008, we also acquired oil and natural gas properties in the San Juan Basin from certain institutional partnerships managed by EnerVest for $117.4 million in cash and 908,954 of our common units.

Director Independence

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

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The audit committee of EV Management selected Deloitte & Touche LLP, an independent registered public accounting firm, to audit our consolidated financial statements for the year ended December 31, 2008. The audit committee's charter requires the audit committee to approve in advance all audit and non–audit services to be provided by our independent registered public accounting firm. All services reported in the audit, audit–related, tax and all other fees categories below with respect to this Annual Report on Form 10–K for the year ended December 31, 2008 were approved by the audit committee.

Fees paid to Deloitte & Touche LLP are as follows:

	2008	2007
Audit fees [(1)]	$ 1,025,500	$ 1,243,560
Audit–related fees	43,700	95,268
Tax fees	–	–
All other fees	–	–
Total	$ 1,069,200	$ 1,338,828

(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:

2.1 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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2.4 Agreement of Sale and Purchase by and among EnerVest Monroe Limited Partnership, EnerVest Monroe Pipeline GP, L.C. and EnerVest Monroe Gathering, Ltd., as Seller, and EnerVest Production Partners, Ltd, as Buyer, dated March 7, 2007 (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 March 14, 2007).

2.5 First Amendment to Agreement of Sale and Purchase by and among EnerVest Monroe Limited Partnership, EnerVest Monroe Pipeline GP, L.C., EnerVest Production Partners, Ltd and EVPP GP, LLC dated March 29, 2007 (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 April 4, 2007).

2.6 Purchase and Sale Agreement between Anadarko E&P Company LP and Kerr–McGee Oil and Gas Onshore LP, as Seller, and EnerVest Energy Institutional Fund X–A, L.P., EnerVest Energy Institutional Fund X–WI, L.P., EnerVest Energy Institutional Fund XI–A, L.P., EnerVest Energy Institutional Fund XI–WI, L.P., EnerVest Management Partners, Ltd., Wachovia Investment Holdings, LLC and EV Properties, L.P. dated April 13, 2007 (Incorporated by reference from Exhibit 2.3 to EV Energy Partners, L.P.'s quarterly report on Form 10–Q filed with the SEC on August 14, 2007).

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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).
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10.10	Registration Rights Agreement, dated February 27, 2007, by and among EV Energy Partners, L.P. and the Purchasers named therein (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 February 28, 2007).
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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

* 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 12, 2009

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 12, 2009
/s/MARK A. HOUSER Mark A. Houser	President, Chief Operating Officer and Director	March 12, 2009
/s/MICHAEL E. MERCER Michael E. Mercer	Senior Vice President and Chief Financial Officer (principal financial officer)	March 12, 2009
/s/FREDERICK DWYER Frederick Dwyer	Controller (principal accounting officer)	March 12, 2009
/s/VICTOR BURK Victor Burk	Director	March 12, 2009
/s/JAMES R. LARSON James R. Larson	Director	March 12, 2009
/s/GEORGE LINDAHL III George Lindahl, III	Director	March 12, 2009
/s/GARY R. PETERSEN Gary R. Petersen	Director	March 12, 2009

EXHIBIT INDEX

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+32.2	Section 1350 Certification of Chief Financial Officer

* Management contract or compensatory plan or arrangement

\+ Filed herewith

Exhibit 10.15

OMNIBUS AGREEMENT EXTENSION

This Omnibus Agreement Extension (“Agreement”) is entered into on December 17, 2008, and is by and between EnerVest, Ltd., (f/k/a EnerVest Management Partners, Ltd.) a Texas limited partnership (“EnerVest”) and EV Energy GP, LP, a Delaware limited partnership (the “General Partner”).

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

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

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

WHEREAS, neither party has terminated the First Omnibus Agreement.

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

1. The First Omnibus Agreement shall continue in effect until December 31, 2009, subject to termination or automatic renewal on such date as provided in the First Omnibus Agreement.

2. The Partnership shall pay EnerVest a fee of $625,000 per month, $7.5 million annually, for the services described in the First Omnibus Agreement, subject to adjustment as provided in Section 3.3 therein.

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

ENERVEST, LTD.

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

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

EV ENERGY GP, L.P.

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

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

EXHIBIT 21.1

EV ENERGY PARTNERS, L.P.
Subsidiaries

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

EXHIBIT 23.1

CAWLEY, GILLESPIE & ASSOCIATES, INC.
PETROLEUM CONSULTANTS

9601 AMBERGLEN BLVD., SUITE 117
AUSTIN, TEXAS 78729-1106
512-249-7000
FAX 512-233-2618

306 WEST SEVENTH STREET, SUITE 302
FORT WORTH, TEXAS 76102-4987
817-336-2461
FAX 817-877-3728

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

MARCH 12, 2009

EV Energy Partners, L.P.
1001 Fannin Street, Suite 800
Houston, Texas 77002

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

As independent petroleum engineers, we hereby consent to all references to our firm included in this Form 10–K for the year ended December 31, 2008 and the Registration Statements on Form S–8 (No. 333-140205) and Form S–3 (No. 333-146428) of EV Energy Partners, L.P. with respect to our estimates of the oil, natural gas and natural gas liquids reserves of EV Energy Partners, L.P. and its predecessors.

Yours very truly,

/s/ W. TODD BROOKER

W. Todd Brooker, P.E.
Vice President
CAWLEY, GILLESPIE & ASSOCIATES, INC.

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 and in Registration Statement No. 333–146428 on Form S–3 of our report dated March 12, 2009, relating to the consolidated financial statements and financial statement schedules of EV Energy Partners, L.P. and the combined financial statements of the Combined Predecessor Entities, and the effectiveness of EV Energy Partners L.P.'s internal control over financial reporting, appearing in this Annual Report on Form 10–K of EV Energy Partners, L.P. for the year ended December 31, 2008.

Houston, Texas
March 12, 2009

EXHIBIT 31.1

CERTIFICATIONS

I, John B. Walker, certify that:

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

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a–15(e) and 15d–15(e)) 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.

Date: March 12, 2009

/s/ JOHN B. WALKER

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

EXHIBIT 31.2

CERTIFICATIONS

I, Michael E. Mercer, certify that:

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

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) 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.

Date: March 12, 2009

/s/ MICHAEL E. MERCER

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

EXHIBIT 32.1

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

In connection with the accompanying report on Form 10–K for the period ended December 31, 2008 of EV Energy, L.P. (the "Partnership") and filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, John B. Walker, President and Chief Executive Officer of EV Management, LLC, the general partner of EV Energy GP, L.P., the general partner of the Partnership, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

Date: March 12, 2009

/s/ JOHN B. WALKER

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

EXHIBIT 32.2

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

In connection with the accompanying report on Form 10–K for the period ended December 31, 2008 of EV Energy, L.P. (the "Partnership") and filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Michael E. Mercer, Chief Financial Officer of EV Management, LLC, the general partner of EV Energy GP, L.P., the general partner of the Partnership, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

Date: March 12, 2009

/s/ MICHAEL E. MERCER

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