LEGACY RESERVES LP
Form 10-K
March 06, 2009

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

þ **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

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission file number 1-33249

Legacy Reserves LP

(Exact name of registrant as specified in its charter)

Delaware *(State or other jurisdiction of incorporation or organization)*	**16-1751069** *(I.R.S. Employer Identification No.)*
303 W. Wall Street, Suite 1400 **Midland, Texas** *(Address of principal executive offices)*	**79701** *(Zip Code)*

Registrant's telephone number, including area code:
(432) 689-5200

Securities registered pursuant to Section 12(b) of the Act:
Units representing limited partner interests listed on the NASDAQ Stock Market LLC.
Securities registered pursuant to 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 o No þ

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 o No þ

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 þ No o

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 registrants knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ

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

Large accelerated filer o Accelerated filer þ Non-accelerated filer o Smaller reporting company o

(Do not check if a 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 o No þ

The aggregate market value of units held by non-affiliates of the registrant was approximately $470.7 million on June 30, 2008, based on $24.81 per unit, the last reported sales price of the units on the NASDAQ Global Select Market on such date.

31,074,339 units representing limited partner interests in the registrant were outstanding as of March 5, 2009.

DOCUMENTS INCORPORATED BY REFERENCE

Parts of the definitive proxy statement for the registrants 2009 annual meeting of unitholders are incorporated by reference into Part III of this annual report on Form 10-K.

LEGACY RESERVES LP

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GLOSSARY OF TERMS

Bbl. One stock tank barrel or 42 U.S. gallons liquid volume.

Bcf. Billion cubic feet.

Boe. One barrel of oil equivalent determined using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Boe/d. Barrels of oil equivalent per day.

Btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Development project. A drilling or other project which may target proven reserves, but which generally has a lower risk than that associated with exploration projects.

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

Dry hole or well. 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.

Hydrocarbons. Oil, NGLs and natural gas are all collectively considered hydrocarbons.

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

MBoe. One thousand barrels of crude oil equivalent, using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Mcf. One thousand cubic feet.

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

MMBoe. One million barrels of crude oil equivalent, using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

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

NGLs. The combination of ethane, propane, butane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

NYMEX. New York Mercantile Exchange.

Oil. Crude oil, condensate and natural gas liquids.

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

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 developed non-producing or PDNPs. Proved oil and natural gas reserves that are developed behind pipe or shut-in or that can be recovered through improved recovery only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells that were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion prior to the start of production.

Proved reserves. Proved oil and natural gas reserves are the estimated quantities of natural gas, crude oil and natural gas liquids that geological and engineering data demonstrates 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.

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. Proved oil and natural gas 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 re-completion. 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 proven effective by actual tests in the area and in the same reservoir.

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

Reserve acquisition cost. The total consideration paid for an oil and natural gas property or set of properties, which includes the cash purchase price and any value ascribed to units issued to a seller adjusted for any post-closing items.

R/P ratio (reserve life). The reserves as of the end of a period divided by the production volumes for the same period.

Reserve replacement. The replacement of oil and natural gas produced with reserve additions from acquisitions, reserve additions and reserve revisions.

Reserve replacement cost. An amount per BOE equal to the sum of costs incurred relating to oil and natural gas property acquisition, exploitation, development and exploration activities (as reflected in our year-end financial statements for the relevant year) divided by the sum of all additions and revisions to estimated proved reserves, including reserve purchases. The calculation of reserve additions for each year is based upon the reserve report of our independent engineers. Management uses reserve replacement cost to compare our company to others in terms of our historical ability to increase our reserve base in an economic manner. However, past performance does not necessarily reflect future reserve replacement cost performance. For example, increases in oil and natural gas prices in recent years have increased the economic life of reserves, adding additional reserves with no required capital expenditures. On the other hand, increases in oil and natural gas prices have increased the cost of reserve

purchases and reserves added through development projects. The reserve replacement cost may not be indicative of the economic value added of the reserves due to differing lease operating expenses per barrel and differing timing of production.

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

Standardized measure. The present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with assumptions required by the Financial Accounting Standards Board and the Securities and Exchange Commission (using prices and costs in effect as of the period end date) without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization, and discounted using an annual discount rate of 10%. Because we are a limited partnership that allocates our taxable income to our unitholders, no provisions for federal or state income taxes have been provided for in the calculation of standardized measure. Standardized measure does not give effect to derivative transactions.

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 oil and natural gas 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 the right to a share of production.

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

CAUTIONARY STATEMENT
REGARDING FORWARD-LOOKING INFORMATION

This document contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control, which may include statements about:

- our business strategy;
- the amount of oil and natural gas we produce;
- the price at which we are able to sell our oil and natural gas production;
- our ability to acquire additional oil and natural gas properties at economically attractive prices;
- our drilling locations and our ability to continue our development activities at economically attractive costs;
- the level of our lease operating expenses, general and administrative costs and finding and development costs, including payments to our general partner;
- the level of our capital expenditures;
- our future operating results; and
- our plans, objectives, expectations and intentions.

All of these types of statements, other than statements of historical fact included in this document, are forward-looking statements. In some cases, you can identify forward-looking statements by terminology such as “may,” “could,” “should,” “expect,” “plan,” “project,” “intend,” “anticipate,” “believe,” “estimate,” “predict,” “potent “continue,” the negative of such terms or other comparable terminology.

The forward-looking statements contained in this document are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management’s assumptions about future events may prove to be inaccurate. All readers are cautioned that the forward-looking statements contained in this document are not guarantees of future performance, and our expectations may not be realized or the forward-looking events and circumstances may not occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to factors described in Item 1A. under “Risk Factors.” The forward-looking statements in this document speak only as of the date of this document; we disclaim any obligation to update these statements unless required by securities law, and we caution you not to unduly rely on them.

PART I

ITEM 1. *BUSINESS*

References in this annual report on Form 10-K to “Legacy Reserves,” “Legacy,” “we,” “our,” “us,” or like terms prior to March 15, 2006 refer to the Moriah Group, Legacy Reserves LP’s predecessor, including the oil and natural gas properties we acquired in exchange for units and cash from the Moriah Group, the Brothers Group, H2K Holdings, MBN Properties, our Founding Investors, as discussed in Note 4 to our Consolidated Financial Statements, and certain charitable foundations in connection with our private equity offering on March 15, 2006. When used for periods from March 15, 2006 forward, those terms refer to Legacy Reserves LP and its subsidiaries.

Legacy Reserves LP

We are an independent oil and natural gas limited partnership headquartered in Midland, Texas, and are focused on the acquisition and development of oil and natural gas properties primarily located in the Permian Basin and Mid-continent regions of the United States. We were formed in October 2005 to own and operate the oil and natural gas properties that we acquired from our Founding Investors and three charitable foundations in connection with the closing of our private equity offering on March 15, 2006. On January 18, 2007, we completed our initial public offering.

Our primary business objective is to generate stable cash flows allowing us to make cash distributions to our unitholders and to support and increase quarterly cash distributions per unit over time through a combination of acquisitions of new properties and development of our existing oil and natural gas properties.

We have grown primarily through two activities: the acquisition of producing oil and natural gas properties and the development of producing properties as opposed to higher risk exploration of unproved properties.

Our oil and natural gas production and reserve data as of December 31, 2008 are as follows:

- we had proved reserves of approximately 30.8 MMBoe, of which 68% were oil and natural gas liquids and 89% were classified as proved developed producing, 2% were proved developed non-producing, and 9% were proved undeveloped;
- our proved reserves had a standardized measure of $235.0 million; and
- our proved reserves to production ratio was approximately 10 years based on the average daily net production of 8,553 Boe/d for the three months ended December 31, 2008.

Impact of Oil and Natural Gas Price Decline

We experienced a reduction in our proved reserves from 32.1 MMBoe at December 31, 2007, to 30.8 MMBoe at December 31, 2008, reflecting a downward revision of 8.1 MMBoe due to reduced oil, NGL and natural gas prices, the addition of 8.6 MMBoe through acquisitions (determined using December 31, 2008 NYMEX near month futures prices of $44.60 per Bbl and $5.62 per MMBtu for oil and natural gas, respectively) and 2008 total production of 2.775 MMBoe. Our standardized measure decreased from $690.5 million at December 31, 2007 to $235.0 million at December 31, 2008, due to the dramatic decline in oil, NGL and natural gas prices in the second half of 2008 from a high of $145.31 per Bbl and $13.58 per MMBtu, in July, to $44.60 per Bbl and $5.62 per MMBtu at year-end, with $456.1 million of the reduction in standardized measure caused by the change in commodity prices, net of production costs. Our proved reserve volumes and standardized measure are calculated based on these significantly lower year-end prices compared to year-end 2007 oil prices of $95.98 per Bbl and natural gas prices of $7.48 per MMBtu. Neither the decline in proved reserve volumes nor the decrease in standardized measure takes into account the fair market value of our commodity derivatives positions, which increased from a net liability of $82.3 million at December 31, 2007 to a $134.9 million net asset as of December 31, 2008. Further, unlike reserve volumes and the standardized measure, which are valued based on year-end prices, our operating and capital costs incurred over the prior twelve months were elevated due to higher industry activity levels and higher costs such as electricity, steel and diesel fuel, related to high oil and natural gas prices (which

averaged $99.75 per Bbl and $8.90 per MMBtu for the year ended December 31, 2008). The mismatch between low year-end oil and natural gas prices (and as a result, the value of our reserves) and elevated operating and capital costs reduced our proved reserves to production ratio from 14 years at December 31, 2007 to approximately 10 years at December 31, 2008. Furthermore, based on current oil and natural gas prices, approximately 50% of our drilling projects or proved undeveloped reserves became uneconomic due to the elevated capital costs combined with the depressed oil and natural gas prices used to determine their value. If oil, NGL and natural gas prices improve from year end 2008 levels, we would expect our reserve estimates to have positive revisions due to changes in prices.

Increase in Depletion, Depreciation, Amortization and Accretion

The severe loss in proved reserve volumes due to lower oil and natural gas prices increased our depletion, depreciation, amortization and accretion ("DD&A") expense. The DD&A rate is determined by the annual net hydrocarbon production divided by the sum of the year-end proved reserves and the annual production. Given that the year-end proved reserve balance has been reduced dramatically, the DD&A rate increased to $22.82 per Boe for the year ended December 31, 2008, from $15.66 per Boe in for the year ended December 31, 2007. To the extent proved reserves are restored due to higher hydrocarbon prices in the future and/or lower production costs, the DD&A rate could reduce in the future. Similarly, should hydrocarbon prices and proved reserves decline further, the DD&A rate could increase further.

Impairment

As previously discussed, the combination of low year-end prices and increased production and capital costs reduced the calculated economic life of properties. The reduction in economic life and lower net revenues associated with lower hydrocarbon prices was the primary cause of impairment on 101 of our 239 fields, which amounted to $76.9 million for the year ended December 31, 2008, an increase from $3.2 million for the year ended December 31, 2007. Legacy compares the net capitalized costs of proved oil and natural gas properties to the estimated undiscounted future net cash flows using management's expectations of future oil and natural gas prices. These future price scenarios reflect our estimation of future price volatility. If net capitalized costs exceed estimated undiscounted future net cash flows, the net capitalized costs are written down, or impaired, so that net capitalized costs equal the present value, discounted at 10%, of future net cash flows using management's expectations of future oil and natural gas prices.

Acquisition Activities

During the year ended December 31, 2008, we invested approximately $242.6 million, including non-cash asset retirement obligations, in 15 acquisitions of proved oil and natural gas properties. Based on reserve data prepared internally at the time of these acquisitions, we added a total of approximately 14.3 MMBoe (8.6 MMBoe based on oil and natural gas prices of $41.00 and $5.71 per Bbl and MMbtu, respectively, as of December 31, 2008) of proved reserves at an average reserve acquisition cost of $15.18 per Boe, ($25.25 per Boe based on December 31, 2008 oil and natural gas prices described above) which excludes associated non-cash asset retirement obligations. The recent acquisitions discussed below are also included in the reserve acquisition cost calculation, along with immaterial acquisitions closed during 2008.

On April 30, 2008, Legacy purchased certain oil and natural gas properties located primarily in the Permian Basin and to a lesser degree in Oklahoma and Kansas from a third party for a net purchase price of $79.2 million. The purchase price was paid with the issuance of 1,345,291 newly issued units valued at $27.0 million and $52.2 million paid in cash ("COP III Acquisition"). The effective date of this purchase was January 1, 2008. The $79.2 million purchase price was allocated with $19.6 million recorded as lease and well equipment and $59.6 million as leasehold cost. Asset retirement obligations of $4.0 million were recorded in connection with this acquisition. The operating results from these COP III Acquisition properties have been included from their acquisition on April 30, 2008.

On May 2, 2008, Legacy entered into a non-monetary exchange with Devon Energy in which Legacy exchanged its 12.9% non-operated working interest in the Reeves Unit, an oil and natural gas producing property located in Yoakum County, Texas, for a 60% interest in two operated properties. Legacy and Devon agreed upon a fair value of $7.7 million, prior to a net purchase price adjustment decrease of approximately $1.2 million,

for both the Reeves Unit working interest and the acquired properties. Prior to the exchange, Legacy's basis in the Reeves Unit was $2.8 million. Due to the commercial substance of the transaction, the excess fair value of $3.7 million above the carrying value of the Reeves Unit was recorded as a gain on sale of discontinued operation for the year ended December 31, 2008. Due to immateriality, Legacy has not reflected the operating results of the Reeves Unit separately as a discontinued operation for any of the periods presented.

On October 1, 2008, Legacy purchased all of the membership interests of Pantwist LLC (the Pantwist Acquisition) from Cano Petroleum, Inc. for a net purchase price of $40.6 million. Pantwist owns certain oil and natural gas properties in Carson, Gray, Hutchison and Moore counties in the Texas Panhandle. The effective date of this purchase was July 1, 2008. The $40.6 million purchase price was allocated with $3.5 million recorded as lease and well equipment and $37.1 million recorded as leasehold costs. Asset retirement obligations of $2.2 million were recorded in connection with this acquisition. The operations of the Pantwist properties have been included from their acquisition on October 1, 2008.

Development Activities

We have also added reserves and production through development projects on our existing and acquired properties. Our development projects include accessing additional productive formations in existing well-bores, formation stimulation, artificial lift equipment enhancement, infill drilling on closer well spacing, secondary (waterflood) and tertiary (miscible CO_2 and nitrogen) recovery projects, drilling for deeper formations and completing unconventional and tight formations.

As of December 31, 2008, we identified 94 gross (53.6 net) proved undeveloped drilling locations and 47 gross (19.9 net) re-completion and re-fracture stimulation projects. Excluding acquisitions, we expect to make capital expenditures of approximately $20.0 million during the year ending December 31, 2009, including drilling 33 gross (20.5 net) development wells and executing 22 gross (10.3 net) re-completions and re-fracture stimulations.

Oil and Natural Gas Derivative Activities

Our business strategy includes entering into oil and natural gas derivative contracts which are designed to mitigate price risk for a majority of our oil, NGL and natural gas production over a three- to five-year period. We have entered into these derivative contracts for approximately 70% of our expected oil, NGL and natural gas production from total proved reserves for the year ending December 31, 2009. We have also entered into these derivative contracts for over 50%, on average, of our expected oil, NGL and natural gas production from total proved reserves for 2010 through 2013. The majority of our derivative contracts are in the form of fixed price swaps for NYMEX WTI oil, Mont Belvieu OPIS natural gas liquids components, NYMEX Henry Hub natural gas, West Texas Waha natural gas and ANR-Oklahoma natural gas. In July 2006, we entered into basis swaps to receive floating NYMEX Henry Hub natural gas prices less a fixed basis differential and pay prices based on the floating Waha index, a natural gas hub in West Texas. The prices that we receive for our Permian Basin natural gas sales follow Waha more closely than NYMEX Henry Hub. In December 2008, we entered into basis swaps to receive floating NYMEX Henry Hub natural gas prices less a fixed basis differential and pay prices based on the floating ANR-Oklahoma index, a natural gas hub in Oklahoma. The prices that we receive for our Panhandle and Oklahoma natural gas sales follow ANR-Oklahoma more closely than NYMEX Henry Hub. The basis swaps thereby provide a better match between our natural gas sales and the settlement payments on our natural gas swaps. We have entered into basis swaps covering approximately 100% of our NYMEX Henry Hub natural gas basis differential risk on our NYMEX Henry Hub natural gas swaps.

Business Strategy

The key elements of our business strategy are to:

- Make accretive acquisitions of producing properties generally characterized by long-lived reserves with stable production and reserve development potential;

- Add proved reserves and maximize cash flow and production through development projects and operational efficiencies;
- Maintain financial flexibility; and
- Reduce commodity price risk through oil, NGL and natural gas derivative transactions.

Marketing and Major Purchasers

For the years ended December 31, 2008, 2007 and 2006, Legacy sold oil and natural gas production representing 10% or more of total revenues to purchasers as detailed in the table below:

	2008	2007	2006
Teppco Crude Oil, LP	18%	13%	5%
Plains Marketing, LP	10%	13%	14%
Navajo Crude Oil Marketing	5%	11%	12%

Our oil sales prices are based on formula pricing and calculated either using a discount to NYMEX WTI oil or using the appropriate buyers posted price, plus Platts P-Plus monthly average, less the Midland-Cushing differential less a transportation fee.

If we were to lose any one of our oil or natural gas purchasers, the loss could temporarily cause a loss or deferral of production and sale of our oil and natural gas in that particular purchasers service area. If we were to lose a purchaser, we believe we could identify a substitute purchaser. However, if one or more of our larger purchasers ceased purchasing oil or natural gas altogether, the loss of any such purchasers could have a detrimental effect on our production volumes in general and on our ability to find substitute purchasers for our production volumes in a timely manner.

Competition

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. As a result, our competitors may be able to pay more for productive oil and natural gas properties and development projects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional properties and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry.

Seasonal Nature of Business

Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months thereby affecting the price we receive for natural gas. Seasonal anomalies, such as mild winters or hotter than normal summers, sometimes lessen this fluctuation. Demand for natural gas and NGLs can be particularly weak in the fall and spring which, coupled with high inventory levels, could result in the shut-in and deferral of production.

Environmental Matters and Regulation

General. Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection 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 oil and natural gas drilling and production activities;

- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug 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 and state agencies frequently revise environmental laws and regulations, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry 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 operations are subject.

Waste Handling. The Resource Conservation and Recovery Act, or RCRA, and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the federal Environmental Protection Agency, or the EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of crude oil or natural gas are currently regulated under RCRA s non-hazardous waste provisions. However, it is possible that certain oil and natural gas drilling and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third-parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas development and production for many years. Although we believe that 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 our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons were not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to remove previously disposed of substances and wastes, remediate contaminated property, or perform remedial plugging or pit closure operations to prevent future contamination.

Water Discharges. The Federal Water Pollution Control Act, or 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 oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

Air Emissions. The Federal Clean Air Act, and comparable state laws, regulates emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the Federal Clean Air Act and associated state laws and regulations.

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the Department of the 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 the development of oil and natural gas projects.

OSHA and Other Laws and Regulation. We are subject to the requirements of the federal Occupational Safety and Health Act (OSHA) and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under 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 compliance with these applicable requirements and with other OSHA and comparable requirements.

Recent studies have suggested that emissions of certain gases may be contributing to warming of the Earth's atmosphere. In response to these studies, many nations have agreed to limit emissions of "greenhouse gases" pursuant to the United Nations Framework Convention on Climate Change, also known as the "Kyoto Protocol." Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil and natural gas, and refined petroleum products, are "greenhouse gases" regulated by the Kyoto Protocol. Although the United States is not participating in the Kyoto Protocol, several states have adopted legislation and regulations to reduce emissions of greenhouse gases. For example, California adopted the "California Global Warming Solutions Act of 2006," which required the California Air Resources Board to achieve a 25% reduction in emissions of greenhouse gases from sources in California by 2020. Legacy does not conduct any operations in California. Restrictions on emissions of methane or carbon dioxide that may be imposed in various states of the United States could adversely affect our operations and demand for our products. Additionally, the U.S. Supreme Court only recently held in a case, *Massachusetts, et al. v. EPA*, that greenhouse gases fall within the federal Clean Air Act's definition of "air pollutant," which could result in the regulation of greenhouse gas emissions from stationary sources under certain Clean Air Act programs. New legislation or regulatory programs that restrict emissions of greenhouse gases in areas in which we conduct business could have an adverse affect on our operations and demand for our services. Currently, our operations are not adversely impacted by existing state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business.

We believe that we are in substantial compliance with all existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. For instance, we did not incur any material capital expenditures for remediation or pollution control activities for the year ended December 31, 2008. Additionally, as of the date of this document, we are not aware of any environmental issues or claims that require material capital expenditures during 2009. However, we cannot assure you that the passage of more stringent laws or regulations in the future will not have a negative impact on our financial position or results of operations.

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 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 oil and natural gas 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 oil and natural gas 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 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 pro-ration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration 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.

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, or the FERC. Federal and state regulations govern the price and terms for access to natural gas pipeline transportation. The FERC□s regulations for interstate natural gas transmission in some circumstances may also affect the intrastate transportation of natural gas.

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 regulation. The various states regulate the drilling for, and the production, gathering and sale of, oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. For example, Texas currently imposes a 4.6% severance tax on oil production and a 7.5% severance tax on natural gas production. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of natural gas resources. States may regulate rates of production and may establish maximum daily production allowable 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.

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us.

Employees

As of December 31, 2008, we had 98 full-time employees, including 10 petroleum engineers, 9 accountants and 3 landmen, none of whom are subject to collective bargaining agreements. We also contract for the services of independent consultants involved in land, engineering, regulatory, accounting, financial and other disciplines as needed. We believe that we have a favorable relationship with our employees.

Offices

We currently lease approximately 23,446 square feet of office space in Midland, Texas at 303 W. Wall Street, Suite 1400, where our principal offices are located. The lease for our Midland office expires in August 2011.

Available Information

We make available free of charge on our website, www.legacylp.com, 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 the Securities Exchange Act of 1934, as amended, as soon as reasonably practicable after we electronically file such information with, or furnish it to, the SEC.

The information on our website is not, and shall not be deemed to be, a part of this annual report on Form 10-K or incorporated into any of our other filings with the SEC.

ITEM 1A. *RISK FACTORS*

Risks Related to our Business

We may not have sufficient available cash to pay the full amount of our current quarterly distribution or any distribution at all following establishment of cash reserves and payment of fees and expenses, including payments to our general partner.

We may not have sufficient available cash each quarter to pay the full amount of our current quarterly distribution or any distribution at all. The amount of cash we distribute in any quarter to our unitholders may fluctuate significantly from quarter to quarter and may be significantly less than our current quarterly distribution. Under the terms of our partnership agreement, the amount of cash otherwise available for distribution will be reduced by our operating expenses and the amount of any cash reserves that our general partner establishes to provide for future operations, future capital expenditures, future debt service requirements and future cash distributions to our unitholders. Further, our debt agreements contain restrictions on our ability to pay distributions. 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, NGL and natural gas we produce;
- the price at which we are able to sell our oil, NGL and natural gas production;

- the amount and timing of settlements on our commodity and interest rate derivatives;
- whether we are able to acquire additional oil and natural gas properties at economically attractive prices;
- whether we are able to continue our development projects at economically attractive costs;
- the level of our lease operating expenses, general and administrative costs and development costs, including payments to our general partner;
- the level of our interest expense, which depends on the amount of our indebtedness and the interest payable thereon; and
- the level of our capital expenditures.

If we are not able to acquire additional oil and natural gas reserves on economically acceptable terms, our reserves and production will decline, which would adversely affect our business, results of operations and financial condition and our ability to make cash distributions to our unitholders.

We will be unable to sustain distributions at the current level without making accretive acquisitions or substantial capital expenditures that maintain or grow our asset base. Oil and natural gas reserves are characterized by declining production rates, and our future oil and natural gas reserves and production and, therefore, our cash flow and our ability to make distributions are highly dependent on our success in economically finding or acquiring additional recoverable reserves and efficiently developing and exploiting our current reserves. Further, the rate of estimated decline of our oil and natural gas reserves may increase if our wells do not produce as expected. We may not be able to find, acquire or develop additional reserves to replace our current and future production at acceptable costs, which would adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Our future growth may be limited because we distribute all of our available cash to our unitholders, and the recent disruptions in the financial markets may prevent us from obtaining the financing necessary for growth and acquisitions.

Since we will distribute all of our available cash (as defined in our partnership agreement) to our unitholders, our growth may not be as fast as businesses that reinvest their available cash to expand ongoing operations. Further, since we depend on financing provided by commercial banks and other lenders and the issuance of debt and equity

securities to finance any significant growth or acquisitions, the recent disruptions in the global financial markets and the associated severe tightening of credit supply may prevent us from obtaining adequate financing from these sources, and, as a result, our ability to grow, both in terms of additional drilling and acquisitions, will be limited.

If commodity prices decline further or remain at current levels (approximately $40 per Bbl and $4 per MMBtu for NYMEX WTI oil and Henry Hub natural gas, respectively) for a prolonged period, we may be forced to reduce our distribution or not be able to pay distributions at all.

If oil and natural gas prices decline further or remain at current levels over a prolonged period, the value of our reserves would continue to decrease, thereby reducing our cash flow and available credit, which would force us to reduce or suspend our distribution. Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of 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 imports of crude oil and natural gas;

- overall domestic and global economic conditions;
- political and economic conditions in other oil and natural gas producing countries, including embargoes and continued hostilities in the Middle East and other sustained military campaigns, 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;
- the level of consumer product demand;
- weather conditions;
- the impact of the U.S. dollar exchange rates on oil and natural gas prices; and
- the price and availability of alternative fuels.

In the past, the prices of oil and natural gas have been extremely volatile, and we expect this volatility to continue.

If commodity prices decline further and remain depressed for a prolonged period, a significant portion of our development projects may become uneconomic and cause write downs of the value of our oil and gas properties, which may adversely affect our financial condition and our ability to make distributions to our unitholders.

Lower oil and natural gas prices may not only decrease our revenues, but also reduce the amount of oil and natural gas that we can produce economically. Furthermore, the drastically lower oil and natural gas prices experienced in the fourth quarter of 2008 rendered more than half of our development projects uneconomic. The recent decrease in commodity prices has also resulted in a substantial downward adjustment to our estimated proved reserves from a standardized measure of $690.5 million as of December 31, 2007 to $235.0 million as of December 31, 2008. Further, deteriorating commodity prices may cause us to recognize impairments in the value of our oil and gas properties. In the fourth quarter of 2008, we recognized an impairment of $76.9 million. In addition, 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 may incur additional impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken.

Due to regional fluctuations in the actual prices received for our production, the derivative contracts we enter into may not provide us with sufficient protection against price volatility since they are based on indexes related to different and remote regional markets.

We sell our natural gas into local markets, the majority of which is produced in West Texas, Southeast New Mexico, the Texas Panhandle and Central Oklahoma and shipped to the Midwest, West Coast and Texas Gulf Coast. While we are paid a local price indexed to or closely related to Waha and ANR-Oklahoma, these indexes are heavily influenced by prices received in remote regional consumer markets less transportation costs. Our existing natural gas swaps are based on Waha and ANR-Oklahoma directly or through basis swaps, and we believe these to be representative of the prices we are paid for our natural gas in the listed regions. These regions account for over 90% of our gas sales. While we have a limited amount of NGL swaps in place, we are not able to effectively offset our NGL price risk though we have used oil as a proxy for NGLs, which in 2008, has proven to be a relatively ineffective hedge as NGL prices have declined more dramatically than oil prices due to the impact of Hurricanes Gustav and Ike on the Gulf Coast NGL processors (also known as fractionators which split the NGL stream into components including ethane, propane, butane, and natural gasoline) and the economic downturn, which has impacted petrochemical plant demand for NGLs, an important feedstock into refining and petrochemical plants.

Fluctuations in price and demand for our natural gas may force us to shut in a significant number of our producing wells, which may adversely impact our revenues and ability to pay distributions to our

unitholders.

We are subject to great fluctuations in the prices we are paid for our natural gas due to a number of factors including regional demand, weather, demand for NGLs which are recovered from our gas stream, and new natural gas pipelines such as the recently completed REX pipeline from the Rocky Mountains to the Midwest which competes with our natural gas in the Midwest. Drilling in shale resources has developed large amounts of new natural gas supplies that have depressed the prices paid for our natural gas, and we expect the shale resources to continue to be drilled and developed by our competitors. We also face the potential risk of shut-in natural gas due to high levels of natural gas and NGL inventory in storage, weak demand due to mild weather and the effects of the economic downturn on industrial demand. Lack of NGL storage in Mont Belvieu where our West Texas and New Mexico NGLs are shipped for processing could cause the processors of our natural gas to curtail or shut-in our natural gas wells and potentially force us to shut-in oil wells that produce associated natural gas. Following Hurricanes Gustav and Ike, when certain Permian Basin natural gas processors were forced to shut down their plants due to the shutdown of the Texas Gulf Coast NGL fractionators, we were able to produce our oil wells and vent or flare the associated natural gas. There is no certainty we will be able to vent or flare natural gas again due to potential changes in regulations. Furthermore we may encounter problems in restarting production of previously shut-in wells.

Our commodity derivative activities may limit our ability to profit from price gains, could result in cash losses and expose us to counterparty risk and as a result could reduce our cash available for distributions.

We have entered into, and we may in the future enter into, oil and natural gas derivative contracts intended to offset the effects of commodity price volatility related to a significant portion of our oil and natural gas production. Many derivative instruments that we employ require us to make cash payments to the extent the applicable index exceeds a predetermined price, thereby limiting our ability to realize the benefit of increases in oil and natural gas prices.

The recent disruptions in the financial markets and the failures of major financial institutions have increased the risk that counterparties in any derivative transaction cannot or will not perform under our derivative contracts. If a counterparty fails to perform and the derivative transaction is terminated, our cash flow, and ability to pay distributions could be adversely impacted.

Further, if our actual production and sales for any period are less than our expected production covered by derivative contracts and sales for that period (including reductions in production due to involuntary shut-ins or operational delays) or if we are unable to perform our drilling activities as planned, we might be forced to satisfy all or a portion of our derivative contracts without the benefit of the cash flow from our sale of the underlying

physical commodity, resulting in a substantial diminution of our liquidity. Under our revolving credit facility, we are prohibited from entering into derivative contracts covering all of our production, and we therefore retain the risk of a price decrease on our volumes not subject to derivative contracts.

The recent disruptions in the financial markets, the substantial restrictions and financial covenants of our revolving credit facility and any negative redetermination of our borrowing base by our lenders could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

We depend on our revolving credit facility for future capital needs. Our revolving credit facility limits the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion. As of March 2, 2009, we had $110 million available for borrowing under our revolving credit facility. Due to drastic decreases in commodity prices and recent disruptions and steep declines in the global financial markets and generally severely tightening credit supply, lenders under our revolving credit facility are expected to decrease our borrowing base at the next redetermination scheduled for April 1, 2009. If the lenders were to decrease the borrowing base to a level below our then outstanding borrowings, which are currently at $300 million, the amount exceeding the revised borrowing base would become immediately due and payable. In addition, our lenders may not honor their *pro rata* share of existing or future total commitments, which may significantly reduce our available borrowing capacity and, as a result, materially adversely affect our financial condition and ability to pay distributions to our unitholders.

Our existing revolving credit facility matures on March 15, 2010. We may not be able to enter into a new revolving credit facility or may have to agree to a new revolving credit facility with terms and conditions much less favorable than our existing revolving credit facility. As a result, all amounts outstanding under our existing revolving credit facility on March 15, 2010 would become immediately due and payable. Any replacement credit facility may be on less attractive terms and impose more severe restrictive covenants on us, and the credit commitments and borrowing base available under such new credit facility may be significantly lower than the current commitments and borrowing base. As a result, our ability to fund our operations and growth projects may be severely limited, adversely affecting our financial condition and ability to pay distributions to our unitholders.

Our existing revolving credit facility restricts and any future credit facility is expected to restrict, among other things, our ability to incur debt and pay distributions, and requires and will require us to comply with certain financial covenants and ratios. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control, such as the recent disruptions in the financial markets. Our failure to comply with any of the restrictions and covenants under our revolving credit facility could result in a default under our revolving credit facility. A default under our revolving credit facility could cause all of our existing indebtedness to be immediately due and payable.

We are prohibited from borrowing under our revolving credit facility to pay distributions to unitholders if the amount of borrowings outstanding under our revolving credit facility reaches or exceeds 90% of the borrowing base, which is the amount of money available for borrowing, as determined semi-annually by our lenders in their sole discretion. The lenders will redetermine the borrowing base based on an engineering report with respect to our oil and natural gas reserves, which will take into account the prevailing oil and natural gas prices at such time. Any time our borrowings exceed 90% of the then specified borrowing base, our ability to pay distributions to our unitholders in any such quarter is solely dependent on our ability to generate sufficient cash from our operations.

Outstanding borrowings in excess of the borrowing base must be repaid, and, if mortgaged properties represent less than 80% of total value of oil and gas properties used to determine the borrowing base, we must pledge other oil and natural gas properties as additional collateral. We may not have the financial resources in the future to make any mandatory principal prepayments required under our revolving credit facility.

The occurrence of an event of default or a negative redetermination of our borrowing base could adversely affect our business, results of operations, financial condition and our ability to make distributions to our unitholders.

Please read Management s Discussion and Analysis of Financial Condition and Results of Operation Financing Activities.

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

No one can measure underground accumulations of oil and natural gas in an exact way. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, production levels, and operating and development costs. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves which could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Our business depends on gathering and transportation facilities owned by others. Any limitation in the availability of those facilities would interfere with our ability to market the oil and natural gas we

produce.

The marketability of our oil and natural gas production depends in part on the availability, proximity and capacity of gathering and pipeline systems owned by third parties. The amount of oil and natural gas that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering or transportation system, or lack of contracted capacity on such systems. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we are provided only with limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in gathering system or pipeline capacity, or significant delay in the construction of necessary gathering and transportation facilities, could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Our development projects 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 oil and natural gas reserves.

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 reduce our cash available for distribution. We intend to finance our future capital expenditures with cash flow from operations and borrowings under our revolving credit facility. Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- the prices at which our oil and natural gas are sold; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our revolving credit facility decrease as a result of lower oil and/or natural gas 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 revolving credit facility restricts our ability to obtain new financing. If additional capital is needed, we may not be able to obtain debt or equity financing. If cash generated by operations or available under our revolving 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 decline in our oil and natural gas reserves, and could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

We do not control all of our operations and development projects and failure of an operator of wells in which we own partial interests to adequately perform could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Many of our business activities are conducted through joint operating agreements under which we own partial interests in oil and natural gas wells.

If we do not operate wells in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of underlying properties. The success and timing of our development projects on properties operated by others is outside of our control.

The failure of an operator of wells in which we own partial interests to adequately perform operations, or an operators breach of the applicable agreements, could reduce our production and revenues and could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Increases in the cost of or failure of costs to adjust downward for drilling rigs, service rigs, pumping services and other costs in drilling and completing wells could reduce the viability of certain of our development projects.

Higher oil and natural gas prices may also increase the rig count and the cost of rigs and oil field services necessary to implement our development projects. While costs are currently declining, they have not declined as rapidly as hydrocarbon prices. Thus, the reduced value of hydrocarbons may not justify the capital investment and operating expenses associated with a development project until costs decline further. This would delay or cancel certain projects, reducing our production and cash available to distribute. Increased capital requirements for our projects will result in higher reserve replacement costs which could reduce cash available for distribution. Higher project costs could cause certain of our projects to become uneconomic and therefore not to be implemented, reducing our production and cash available for distribution.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Our drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for oil and natural gas can be uneconomic, not only from dry holes, but also from productive wells that do not produce sufficient revenues to be commercially viable.

In addition, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- the high cost, shortages or delivery delays of equipment and services;
- unexpected operational events;
- adverse weather conditions;
- facility or equipment malfunctions;
- title disputes;
- pipeline ruptures or spills;
- collapses of wellbore, casing or other tubulars;
- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- formations with abnormal pressures;
- fires;
- blowouts, craterings and explosions; and
- uncontrollable flows of oil, natural gas or well fluids.

Any of these events can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination, loss of wells and regulatory penalties.

We ordinarily maintain insurance against various losses and liabilities arising from our operations; however, insurance against all operational risks is not available to us. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could therefore occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Increases in interest rates could adversely affect our business, results of operations, cash flows from operations and financial condition.

Since all of the indebtedness outstanding under our revolving credit facility is at variable interest rates, we have significant exposure to increases in interest rates. As a result, our business, results of operations and cash flows may be adversely affected by significant increases in interest rates. Further, an increase in interest rates may cause a corresponding decline in demand for equity investments, in particular for yield-based equity investments such as our units. Any reduction in demand for our units resulting from other more attractive investment opportunities may cause the trading price of our units to decline.

We may have assumed unknown liabilities in connection with the formation transactions and our subsequent acquisitions.

As part of the formation transactions and subsequent acquisitions, our properties may be subject to existing liabilities, some of which may have been unknown at the closing of such transactions. Unknown liabilities might include liabilities for cleanup or remediation of undisclosed or unknown environmental conditions, claims of vendors or other persons (that had not been asserted or threatened prior to the closing of such transactions), tax liabilities and accrued but unpaid liabilities incurred in the ordinary course of business.

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.

One of our growth strategies is to acquire additional oil and natural gas reserves. However, our reviews of acquired properties 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 environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, we often assume environmental and other risks and liabilities in connection with acquired properties.

Our identified drilling location inventories are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management team has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our acreage. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, oil and natural gas prices, costs and drilling results. Our final determination on whether to drill any of these drilling locations will be dependent upon the factors described above as well as, to some degree, the results of our drilling activities with respect to our proved drilling locations. Because of these uncertainties, we do not know if the numerous drilling locations we have identified will be drilled within our expected timeframe or will ever be drilled or if we will be able to

produce oil or natural gas from these or any other potential drilling locations. As such, our actual drilling activities may be materially different from those presently identified, which could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

The inability of one or more of our customers to meet their obligations may adversely affect our financial condition and results of operations.

Substantially all of our accounts receivable result from oil and natural gas sales or joint interest billings to third parties in the energy industry. This concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. In addition, our oil and natural gas derivative transactions expose us to credit risk in the event of nonperformance by counterparties.

We depend on a limited number of key personnel who would be difficult to replace.

Our operations are dependent on the continued efforts of our executive officers, senior management and key employees. The loss of any member of our senior management or other key employees could negatively impact our ability to execute our strategy.

We may be unable to compete effectively with larger companies, which could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash 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 explore 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 productive natural gas properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration and development activities during periods of low oil and natural gas market prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Our inability to compete effectively with larger companies could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

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.

Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. 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. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results could 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 certain reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our units.

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 and production 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. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. All such costs may have a negative effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

Our business is subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for and the production of, oil and natural gas. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Our operations expose us to significant costs and liabilities with respect to environmental and operational safety matters.

We may incur significant costs and liabilities as a result of environmental and safety requirements applicable to our oil and natural gas exploration and production activities. These costs and liabilities could arise under a wide range of federal, state and local environmental and safety laws and regulations, including regulations and enforcement policies, which have tended to become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and to a lesser extent, issuance of injunctions to limit or cease operations. In addition, claims for damages to persons or property may result from environmental and other impacts of our operations.

Strict, joint and several liability may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. New laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. If we were not able to recover the resulting costs through insurance or increased revenues, our ability to make cash distributions to our unitholders could be adversely affected.

Units eligible for future sale may have adverse effects on our unit price and the liquidity of the market for our units.

We cannot predict the effect of future sales of our units, or the availability of units for future sales, on the market price of or the liquidity of the market for our units. Sales of substantial amounts of units, or the perception that such sales could occur, could adversely affect the prevailing market price of our units. Such sales, or the possibility of such sales, could also make it difficult for us to sell equity securities in the future at a time and at a price that we deem appropriate. The Founding Investors and their affiliates, including members of our management, own approximately 39% of our outstanding units. We granted the Founding Investors certain registration rights to have their units registered under the Securities Act. Upon registration, these units will be eligible for sale into the market. Because of the substantial size of the Founding Investors holdings, the sale of a significant portion of these units, or a perception in the market that such a sale is likely, could have a significant impact on the market price of our units. Further, if purchasers in our private equity offerings were to resell a substantial portion of their units, such sales could reduce the market price of our outstanding units.

Risks Related to Our Limited Partnership Structure

Our Founding Investors, including members of our management, own a 39% limited partner interest in us and control our general partner, which has sole responsibility for conducting our business and managing our operations. Our general partner has conflicts of interest and limited fiduciary duties, which may permit it to favor its own interests to the detriment of our unitholders.

Our Founding Investors, including members of our management, own a 39% limited partner interest in us and therefore have the ability to effectively control the election of the entire board of directors of our general partner. 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 our general partner have a fiduciary duty to manage our general partner in a manner beneficial to its owners, our Founding Investors and their affiliates. Conflicts of interest may arise between our Founding Investors and their 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 affiliates over the interests of our unitholders. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires our Founding Investors or their affiliates, other than our executive officers, to pursue a business strategy that favors us;
- our general partner is allowed to take into account the interests of parties other than us, such as our Founding Investors, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders;
- our Founding Investors and their affiliates (other than our executive officers and their affiliates) may engage in competition with us;
- our general partner has limited its liability and reduced its fiduciary duties under our partnership agreement and has also restricted the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty. As a result of purchasing units, unitholders consent to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable state law;
- our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuance of additional partnership securities, and reserves, each of which can affect the amount of cash that is distributed to our unitholders;
- our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is a maintenance capital expenditure, which reduces operating surplus, or a growth capital expenditure, which does not. Such determination can affect the amount of cash that is distributed to our unitholders;
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us;
- 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 intends to limit its liability regarding our contractual and other obligations;
- our general partner controls the enforcement of obligations owed to us by it and its affiliates; and
- our general partner decides whether to retain separate counsel, accountants, or others to perform services for us.

Even if unitholders are dissatisfied they cannot remove our general partner without the consent of unitholders owning at least 66 2/3% of our units, including units owned by our general partner and its affiliates.

Currently, the unitholders are unable to remove our general partner without its consent because our general partner's affiliates own sufficient units to be able to prevent our general partner's removal. 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. Affiliates of our general partner, including members of our management, own 39% of our units.

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

Our Founding Investors and their affiliates (other than our executive officers and their affiliates) may compete directly with us.

Our Founding Investors and their affiliates, other than our general partner and our executive officers and their affiliates, are not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, our Founding Investors or their affiliates, other than our general partner and our executive officers and their affiliates, may acquire, develop and operate oil and natural gas properties or other assets in the future, without any obligation to offer us the opportunity to acquire, develop or operate those assets.

Cost reimbursements due our general partner and its affiliates will reduce our cash available for distribution to our unitholders.

Prior to making any distribution on our outstanding units, we will reimburse our general partner and its affiliates for all expenses they incur on our behalf. Any such reimbursement will be determined by our general partner in its sole discretion. These expenses will include all costs incurred by our general partner and its affiliates in managing and operating us. The reimbursement of expenses of our general partner and its affiliates could adversely affect our ability to pay cash distributions to our unitholders.

Our partnership agreement limits our general partners fiduciary duties to our unitholders and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement:

- permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any unitholder;
- 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;
- provides that our general partner is entitled to make other decisions in good faith if it believes that the decision is in our best interest;

- provides generally that affiliated transactions and resolutions of conflicts of interest not approved by the conflicts committee of the board of directors 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 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 unitholders 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.

Our partnership agreement permits our general partner to redeem any partnership interests held by a limited partner who is a non-citizen assignee.

If we are or become subject to federal, state or local laws or regulations that, in the reasonable determination of our general partner, create a substantial risk of cancellation or forfeiture of any property that we have an interest in because of the nationality, citizenship or other related status of any limited partner, our general partner may redeem the units held by the limited partner at their current market price. In order to avoid any cancellation or forfeiture, our general partner may require each limited partner to furnish information about his nationality, citizenship or related status. If a limited partner fails to furnish information about his nationality, citizenship or other related status within 30 days after a request for the information or our general partner determines after receipt of the information that the limited partner is not an eligible citizen, our general partner may elect to treat the limited partner as a non-citizen assignee. A non-citizen assignee is entitled to an interest equivalent to that of a limited partner for the right to share in allocations and distributions from us, including liquidating distributions. A non-citizen assignee does not have the right to direct the voting of his units and may not receive distributions in kind upon our liquidation.

We may issue an unlimited number of additional units without the approval of our unitholders, which would dilute their existing ownership interest in us.

Our general partner, without the approval of our unitholders, may cause us to issue an unlimited number of additional units. The issuance by us of additional units or other equity securities of equal or senior rank will have the following effects:

- our unitholders proportionate ownership interests in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the risk that a shortfall in the payment of our current quarterly distribution will increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the units may decline.

The liability of our unitholders 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. In some states, including Delaware, a limited partner is only liable if he participates in the control of the business of the partnership. These statutes generally do not define control, but do permit limited partners to engage in certain activities, including, among other actions, taking any action with respect to the dissolution of the partnership, the sale, exchange, lease

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or mortgage of any asset of the partnership, the admission or removal of the general partner and the amendment of the partnership agreement. Our unitholders could, however, be liable for any and all of our obligations as if our unitholders 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

- our unitholders’ right to act with other unitholders 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 our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the distribution, limited partners who received an impermissible 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 transferring limited partner to make contributions to the partnership that are known to such substitute 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.

Tax Risks to Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of additional entity-level taxation by states and localities. If the IRS were to treat us as a corporation or if we were to become subject to a material amount of additional entity-level taxation for state or local tax purposes, then our cash available for distribution to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our 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 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 currently has a top marginal rate of 35%, and would likely pay state and local income tax at the corporate tax rate of the various states and localities imposing a corporate income tax. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available to pay distributions to our unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders likely causing a substantial reduction in the value of our units.

Current law may change, causing us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are subject to an entity-level state tax on the portion of our gross income that is apportioned to Texas. If any additional states were to impose a tax upon us as an entity, the cash available for distribution to our unitholders would be reduced. Finally, the President’s budget for the fiscal year 2010 outlines proposals to eliminate several oil and gas federal income tax incentives, including the repeal of the percentage depletion allowance for oil and natural gas and expensing of intangible drilling costs. It is not possible at this time to predict how legislation or new regulations that may be adopted to address these proposals would impact our business, but any such future laws and regulations could adversely affect the amount of taxable income or loss being allocated to our unitholders and could have a negative impact on the value of our units.

The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a

retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our units may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible to meet the exception for us to be treated as a partnership for U.S. federal income tax purposes that is not taxable as a corporation, or Qualifying Income Exception, affect or cause us to change our business activities, affect the tax considerations of an investment in us, change the character or treatment of portions of our income and adversely affect an investment in our units. For example, in response to certain recent developments, members of Congress are considering substantive changes to the definition of qualifying income under Section 7704(d) of the Internal Revenue Code. Legislation has been proposed that would eliminate partnership tax treatment for certain publicly traded partnerships. Although such legislation would not apply to us as currently proposed, it could be amended prior to enactment in a manner that does apply to us. It is possible that these legislative efforts could result in changes to the existing U.S. tax laws that affect publicly traded partnerships, including us. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of an investment in our units.

Our unitholders may be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Our unitholders are required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from their share of our taxable income.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury regulations, and, accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A successful IRS contest of the federal income tax positions we take may adversely affect the market for our units, and the costs of any contest will reduce our cash available for distribution to our unitholders.

We have not requested any ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from our counsel’s conclusions or the positions we take. 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 disagree with some or all of our counsel’s conclusions or the positions we take. Any contest with the IRS may materially and adversely impact the market for our units and the price at which they trade. In addition, the costs of any contest with the IRS will result in a reduction in cash available to pay distributions to our unitholders and thus will be borne indirectly by our unitholders.

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

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

Tax gain or loss on the disposition of our units could be more or less than expected because prior distributions in excess of allocations of income will decrease our unitholders tax basis in their units.

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

We will treat each purchaser of our units as having the same tax benefits without regard to the units purchased. The IRS may challenge this treatment, which could adversely affect the value of the units.

Because we cannot match transferors and transferees of units, we will adopt depletion, depreciation and amortization positions that may not conform with all aspects of existing Treasury regulations. Our counsel is unable to opine as to the validity of such filing positions. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain on the sale of units and could have a negative impact on the value of our units or result in audits of and adjustments to our unitholders’ tax returns.

A unitholder whose units are loaned to a “short seller” to cover a short sale of units may be considered as having disposed of those units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan may recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a “short seller” to cover a short sale of units may be considered as having disposed of the loaned units, he may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Our counsel has not rendered an opinion regarding the treatment of a unitholder where our units are loaned to a short seller to cover a short sale of our units; therefore, unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

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

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local income 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 now or in the future, even if they do not reside in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently do business and own assets in Texas, New Mexico, Oklahoma, Alabama, Mississippi, Wyoming, North Dakota, Colorado and Arkansas. As we make acquisitions or expand our business, we may do business or own assets in other states in the future. It is the responsibility of each unitholder to file all United States federal, state and local tax returns that may be required of such unitholder. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in our units.

We will be considered to have terminated for tax purposes due to a sale or exchange of 50% or more of our interests within a twelve-month period.

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. 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.

ITEM 1B. *UNRESOLVED STAFF COMMENTS*

None.

ITEM 2. *PROPERTIES*

As of December 31, 2008 we owned interests in producing oil and natural gas properties in 270 fields in the Permian Basin, Texas Panhandle, Oklahoma and several other states, operated 1,603 gross productive wells and owned non-operated interests in 2,247 gross productive wells. The following table sets forth information about our proved oil and natural gas reserves as of December 31, 2008. The standardized measure amounts shown in the table are not intended to represent the current market value of our estimated oil and natural gas reserves. For a definition of "standardized measure" please see the glossary of terms at the beginning of this annual report on Form 10-K.

	As of December 31, 2008				
	Proved Reserves			Standardized Measure	
Field	**MMBoe**	**R/P(a)**	**% Oil and NGLs**	**Amount(b) ($ in Millions)**	**% of Total**
Texas Panhandle Fields	7.4	13	67%	$ 39.3	16.7%
Spraberry	3.7	11	69	34.6	14.7
Denton	1.7	10	86	14.9	6.4
East Binger	2.2	7	79	14.6	6.2
Farmer	1.2	12	65	7.9	3.3
Lea	1.0	17	68	6.7	2.9
Langlie Mattix	0.9	17	86	6.6	2.8
Total — Top 7 fields	18.0	11	72%	$ 124.6	53.0%
All others	12.8	8	63	110.4	47.0
Total	30.8	10	68%	$ 235.0	100.0%

(a) Reserves as of December 31, 2008 divided by annualized fourth quarter production volumes.

(b) Texas margin taxes and the federal income taxes associated with a corporate subsidiary have not been deducted from future production revenues in the calculation of the standardized measure as the impact of these taxes would not have a significant effect on the calculated standardized measure.

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Summary of Oil and Natural Gas Properties and Projects

Our most significant fields are the Texas Panhandle, Spraberry, Denton, East Binger, Farmer, Lea and Langlie Mattix. As of December 31, 2008, these seven fields accounted for approximately 58.4% of our total estimated proved reserves.

Texas Panhandle Fields. The Texas Panhandle fields are located in Carson, Gray, Hartley, Hutchinson, Moore, and Potter Counties, Texas. The fields are produced from multiple formations of Permian age which primarily include the Granite Wash, Brown Dolomite, and Red Cave formations from 2,500 to 4,000 feet. Legacy operates 571 wells (486 producing, 85 injecting) in the Texas Panhandle fields with working interests ranging from 24.5% to 100% and net revenue interests ranging from 23.7% to 100.0%. We also own another 398 wells (387 producing, 11 injecting) with a 9.6% average non-operated working interest. As of December 31, 2008, our properties in the Texas Panhandle fields contained 7.4 MMBoe (67% liquids) of net proved reserves with a standardized measure of $39.3 million. The average net daily production from these fields was 1,512 Boe/d in for the fourth quarter of 2008. The estimated reserve life (R/P) for these fields is 13 years based on the annualized fourth quarter production rate.

Spraberry Field. The Spraberry field is located in Midland, Martin, Reagan and Upton Counties, Texas. This field produces from Spraberry and Wolfcamp age formations from 5,000 to 10,200 feet. We operate 143 active wells (141 producing, 2 injecting) in this field with working interests ranging from 12.9% to 100% and net revenue interests ranging from 9.6% to 90.8%. We also own another 42 wells (41 producing, 1 injecting) with a 6.4% average non-operated working interest. As of December 31, 2008, our properties in the Spraberry field contained 3.7 MMBoe (69% liquids) of net proved reserves with a standardized measure of $34.6 million. The average net daily production from this field was 930 Boe/d for the fourth quarter of 2008. The estimated reserve life (R/P) for this field is 11 years based on the annualized fourth quarter production rate.

Four operated and four non-operated wells were drilled on Legacy Reserves properties in the Spraberry Field in 2008. We have identified 13 more proved undeveloped projects and 6 behind-pipe or proved developed non-producing re-completion projects in this field.

Denton Field. The Denton field is located in Lea County, New Mexico. The Devonian Formation at depths of 11,000 to 12,700 feet is the primary reservoir in the Denton field. Additional production has been developed in the Wolfcamp Formation at depths of 8,900 to 9,600 feet. We operate 17 wells in the Denton field with working interests ranging from 86% to 100% and net revenue interests ranging from 75.1% to 87.5%. We also own another 6 producing wells with a 15.0% average non-operated working interest. As of December 31, 2008, our properties in the Denton field contained 1.7 MMBoe (86% liquids) of net proved reserves with a standardized measure of $14.9 million. The average net daily production from this field was 472 Boe/d for the fourth quarter of 2008. The estimated reserve life (R/P) for the field is 10 years based on the annualized fourth quarter production rate.

East Binger Field. The East Binger field is located in Caddo County, Oklahoma. The Marchand Sand, at depths of 9,700 to 10,100 feet, is the primary reservoir in the East Binger Field. The East Binger Unit, the major property in the field, is an active miscible nitrogen injection project and is operated by Binger Operations, LLC (BOL), of which Legacy owns 50%. BOL operates 87 wells (52 producing, 35 injecting) in the East Binger field, and Legacy Reserves owns a working interest of 54.5% and net revenue interest of 45.8% in the East Binger Unit. As of December 31, 2008, our properties in the East Binger field contained 2.2 MMBoe (79% liquids) of net proved reserves with a standardized measure of $14.6 million. The average net daily production from this field was 842 Boe/d for the fourth quarter of 2008. The estimated reserve life (R/P) for the field is 7 years based on the annualized fourth quarter production rate.

Two infill wells were drilled in the East Binger Unit in 2008 and we have 8 more proved undeveloped projects identified in this field.

Farmer Field. The Farmer field is located in Crockett and Reagan Counties, Texas. The San Andres Formation at depths of 2,100 to 2,600 feet is the primary reservoir in the Farmer field. We operate 158 wells (150 producing, 8 injecting) in the Farmer field with a 100.0% average working interest and a net revenue interest ranging from 80.8% to 87.5%. As of December 31, 2008, our properties in the Farmer field contained 1.2 MMBoe (65% liquids) of net proved reserves with a standardized measure of $7.9 million. The average net daily production from this field was 268 Boe/d for the fourth quarter of 2008. The estimated reserve life (R/P) for the field is 12 years based on the annualized fourth quarter production rate.

The Farmer field has been developed using 20-acre spacing with the exception of a pilot 10-acre spacing area that includes eleven 10-acre wells. We currently have 8 10-acre proved undeveloped locations in this field and an additional 133 unproved 10-acre locations.

Lea Field. The Lea field is located in Lea County, New Mexico. This field produces from the Devonian Formation at depths of 14,200 to 14,600 feet, the Morrow Formation at depths of 12,800 to 13,200 feet and the Bone Spring Formation at depths of 9,300 to 10,500 feet. We operate 14 wells (12 producing, 2 injection) in the Lea Field with a 68.7% average working interest and a 58.1% average net revenue interest. We also own another eight active producing wells with a 12.6% average non-operated working interest. As of December 31, 2008, our properties in the Lea Field contained 1.0 MMBoe (68% liquids) of net proved reserves with a standardized measure of $6.7 million. The average net daily production from this field was 150 Boe/d for the fourth quarter of 2008. The estimated reserve life (R/P) for the field is 17 years based on the annualized fourth quarter production rate.

Three non-operated wells were drilled on Legacy Reserves properties in the Lea Field in 2008. We have identified 4 proved undeveloped projects and 1 behind-pipe or proved developed non-producing re-completions projects in this field.

Langlie Mattix Field. The Langlie Mattix field is located in Lea County, New Mexico. The Queen Formation at depths of 3,400 to 3,800 feet is the primary reservoir in the Langlie Mattix field. We operate 98 wells (75 producing, 23 injecting) in the Langlie Mattix Penrose Sand Unit, a subdivision of the Langlie Mattix Field, with a 51.7% average working interest and a 44.7% average net revenue interest. We also operate two other properties with five active producing wells with 100% and 82.4% working interests and 82.0% and 67.4% net revenue interests, respectively. As of December 31, 2008, our properties in the Langlie Mattix field contained 0.9 MMBoe (86% liquids) of net proved reserves with a standardized measure of $6.6 million. The average net daily production from this field was 152 Boe/d for the fourth quarter of 2008. The estimated reserve life (R/P) for the field is 17 years based on the annualized fourth quarter production rate.

The Langlie Mattix Penrose Sand Unit was drilled in the late 1930s and early 1940s on 40-acre spacing. Waterflooding commenced in 1958. There have been a total of 26 20-acre infill wells drilled on the Unit in four different drilling programs from 1983 to 2007. All four 20-acre infill drilling programs were successful. We have 20 more proved undeveloped locations and an additional 44 unproved 20-acre locations.

Oil and Natural Gas Data

Proved Reserves

The following table sets forth a summary of information related to our estimated net proved reserves as of the dates indicated based on reserve reports prepared by LaRoche Petroleum Consultants, Ltd. The estimates of net proved reserves have not been filed with or included in reports to any federal authority or agency. Standardized measure amounts shown in the table are not intended to represent the current market value of our estimated oil and natural gas reserves.

	As of December 31,		
	2008	**2007**	**2006**
Reserve Data:			
Estimated net proved producing reserves:			
Oil (MMBbls)	16.6	19.6	13.4
Natural Gas Liquids (MMBbls)	4.3	4.0	
Natural Gas (Bcf)	59.3	50.9	32.5
Total (MMBoe)	30.8	32.1	18.8
Proved developed reserves (MMBoe)	28.0	29.0	15.8
Proved undeveloped reserves (MMBoe)	2.8	3.1	3.0
Proved developed reserves as a percentage of total proved reserves	91%	90%	84%

Standardized measure (in millions)(a)	$ 235.0	$ 690.5	$ 240.6
Oil and Natural Gas Prices(b)			
Oil NYMEX WTI per Bbl	$ 41.00	$ 92.50	$ 57.75
Natural gas NYMEX Henry Hub per MMBtu	$ 5.71	$ 6.80	$ 5.64

(a) Standardized measure is the present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with assumptions required by the Financial Accounting Standards Board and the Securities and Exchange Commission (using prices in effect as of the period end date and costs over the prior period) without giving effect to non-property related expenses such as general administrative expenses and debt service or to depletion, depreciation and amortization and discounted using an annual discount rate of 10%. Because we are a limited partnership that allocates our taxable income to our unitholders, no provision for federal or state income taxes has been provided for in the calculation of standardized measure. Standardized measure does not give effect to derivative transactions. For a description of our derivative transactions, please read Managements Discussion and Analysis of Financial Condition and Results of Operation Cash Flow from Operations.

(b) Oil and natural gas prices as of each date are based on NYMEX physical spot prices per Bbl of oil and per MMBtu of natural gas at such date, with these representative prices adjusted by property to arrive at the appropriate net sales price. These prices correlate to the NYMEX West Texas Intermediate near-month futures prices of $44.60, $95.98 and $61.05 as of December 31, 2008, 2007 and 2006, respectively, and the NYMEX Henry Hub near month futures prices of $5.62, $7.48 and $6.30 as of December 31, 2008, 2007 and 2006, respectively.

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 reserves that are expected to be recovered from new wells on undrilled acreage for which the existence and recoverability of such reserves can be estimated with reasonable certainty, or from existing wells on which a relatively major expenditure is required for re-completion.

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 Our estimated reserves are based on many assumptions that may prove inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves. Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. Standardized measure amounts shown above should not be construed as the current market value of our estimated oil and natural gas reserves. The 10% discount factor used to calculate standardized measure, which is required by Financial Accounting Standard 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.

From time to time, we engage LaRoche Petroleum Consultants, Ltd. to prepare a reserve and economic evaluation of properties that we are considering purchasing. Neither LaRoche Petroleum Consultants, Ltd. nor any of its employees have any interest in those properties, and the compensation for these engagements is not contingent on their estimates of reserves and future net revenues for the subject properties. During 2008, 2007 and 2006, we paid LaRoche Petroleum Consultants, Ltd. approximately $225,074, $143,900 and $246,992, respectively, for such reserve and economic evaluations.

Production and Price History

The following table sets forth a summary of unaudited information with respect to our production and sales of oil and natural gas for the periods indicated, including the historical data of Legacy Reserves LP (formerly the Moriah Group) for the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008(a)	**2007(b)**	**2006(c)**
Production:			
Oil (MBbl)	1,660	1,179	749
Natural gas liquids (Mgal)	12,977	5,295	
Gas (MMcf)	4,838	3,052	2,200
Total (MBOE)	2,775	1,814	1,116
Average daily production (BOE per day)	7,582	4,970	3,058
Average sales price per unit (excluding swaps):			
Oil (per Bbl)	$ 95.16	$ 70.65	$ 60.55
NGL (per Gal)	$ 1.22	$ 1.42	$
Gas (per Mcf)	$ 8.60	$ 7.02	$ 6.57
Combined (per BOE)	$ 77.63	$ 61.87	$ 53.58
Average sales price per unit (including realized swap gains/losses)(d):			
Oil (per Bbl)	$ 72.16	$ 67.58	$ 51.65(e)
NGL (per Gal)	$ 0.99	$ 1.30	$
Gas (per Mcf)	$ 8.80	$ 8.48	$ 9.48
Combined (per BOE)	$ 63.13	$ 61.99	$ 53.35(e)
Average unit costs per BOE:			
Production costs, excluding production and other taxes	$ 18.74	$ 14.96	$ 14.28
Production and other taxes	$ 4.58	$ 4.35	$ 3.36
General and administrative	$ 4.11	$ 4.63	$ 3.31
Depletion, depreciation and amortization	$ 22.82	$ 15.66	$ 16.48

(a) Reflects the production and operating results of the COP III and Pantwist acquisition properties from the closing dates of such acquisitions through December 31, 2008.

(b) Reflects the production and operating results of the oil and natural gas properties acquired in the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC and Summit Acquisitions from the closing dates of such acquisitions through December 31, 2007.

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(c) Reflects the production and operating results of the oil and natural gas properties acquired in the March 15, 2006 formation transactions and the South Justis, Farmer Field and Kinder Morgan acquisitions from the closing dates of such acquisitions through December 31, 2006.

(d) Includes only the realized gains (losses) from Legacys oil and natural gas swaps.

(e) Includes the effect of approximately $4.0 million of derivative premiums for the year ended December 31, 2006 to cancel and reset 2007 oil swaps from $60.00 to $65.82 per barrel for 372,000 barrels and for 2008 oil swaps from $60.50 to $66.44 per barrel for 348,000 barrels, which reflected the prevailing oil swap market at the time of the reset.

Productive Wells

The following table sets forth information at December 31, 2008 relating to the productive wells in which we owned a working interest as of that date. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we own an interest, and net wells are the sum of our fractional working interests owned in gross wells.

	Oil		Natural Gas	
	Gross	**Net**	**Gross**	**Net**
Operated	1,436	1,160	167	149
Non-operated	1,797	192	450	73
Total	3,233	1,352	617	221

Developed and Undeveloped Acreage

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

	Developed Acreage(a)		Undeveloped Acreage(b)	
	Gross(c)	**Net(d)**	**Gross(c)**	**Net(d)**
Total	430,522	146,993	6,200	865

(a) Developed acres are acres spaced or assigned to productive wells or wells capable of production.

(b) Undeveloped acres are acres which are not held by commercially producing wells, regardless of whether such acreage contains proved reserves. All of our proved undeveloped locations are located on acreage currently held by production.

(c) A gross acre is an acre in which we own a working interest. The number of gross acres is the total number of acres in which we own a working interest.

(d) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Drilling Activity

The following table sets forth information, on a combined basis, with respect to wells completed by Legacy during the years ended December 31, 2008, 2007 and 2006. The drilling activities associated with the properties acquired in the Farmer Field acquisition (June 29, 2006), the South Justis acquisition (June 29, 2006) and the Kinder Morgan acquisition (July 31, 2006) are included for all periods subsequent to those acquisition dates. The drilling activities associated with the properties acquired in the Binger acquisition (April 16, 2007), the Ameristate acquisition (May 1, 2007), the TSF acquisition (May 25, 2007), the Raven Shenandoah acquisition (May 31, 2007), the Raven OBO acquisition (August 3, 2007), the TOC acquisition (October 1, 2007) and the

Summit acquisition (October 1, 2007) are included for all periods subsequent to those acquisition dates. The drilling activities

associated with the properties acquired in the COP III acquisition (April 30, 2008) and the Pantwist acquisition (October 1, 2008) are included for all periods subsequent to those acquisition dates. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the numbers of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of oil and natural gas, regardless of whether they produce a reasonable rate of return.

	Year Ended December 31,		
	2008	**2007**	**2006**
Gross:			
Development			
Productive	23	29	14
Dry	—	—	2
Total	23	29	16
Exploratory			
Productive	—	—	—
Dry	—	—	—
Total	—	—	—
Net:			
Development			
Productive	14.1	13.0	6.2
Dry	—	—	1.3
Total	14.1	13.0	7.5
Exploratory			
Productive	—	—	—
Dry	—	—	—
Total	—	—	—

Summary of Development Projects

We are currently pursuing an active development strategy. We estimate that our capital expenditures for the year ending December 31, 2009 will be approximately $20.0 million for development drilling, re-completions and re-fracture stimulation and other development related projects to implement this strategy. We intend to drill 33 gross (20.5 net) development wells and execute 22 gross (10.3 net) re-completions and re-fracture simulations projects. All of these development projects are located in the Permian Basin and the East Binger field in Oklahoma. We will consider adjustments to this capital program based on our assessment of additional development opportunities that are identified during the year and the cash available to invest in our development projects.

Operations

General

We operate approximately 65% of our net daily production of oil and natural gas. We design and manage the development, re-completion or workover for all of the wells we operate and supervise operation and maintenance activities. We do not own drilling rigs or other oil field services equipment used for drilling or maintaining wells on properties we operate except for two single pole pulling units and a cable tool rig used for shallow well work in the Texas Panhandle fields. Independent contractors engaged by us provide all the equipment and personnel associated with these activities. We employ drilling, production, and reservoir engineers, geologists and other specialists who have worked and will work to improve production rates, increase reserves, and lower the cost of operating our oil and natural gas properties. We also employ field operating personnel including production superintendents, production foremen, production technicians and lease operators. We charge the non-operating partners an operating fee for operating the wells, typically on a fee per well-operated basis. Our non-operated wells are managed by third-party operators who are typically independent oil and natural gas companies.

Oil and Natural Gas Leases

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any well drilled on the lease premises. In the Permian Basin, this amount generally ranges from 12.5% to 33.7%, resulting in an 87.5% to 66.3% net revenue interest to us. Most of our leases are held by production and do not require lease rental payments.

South Justis Unit Operating Agreement

In connection with our acquisition of the South Justis Unit from Henry Holding LP on June 29, 2006, we became the successor in interest to Henry Holding LP as unit operator under the Unit Operating Agreement. As unit operator, we are entitled to receive from the other working interest owners a per well operating fee which we expect to be an aggregate of $1.7 million annually and is subject to an annual cost escalator. Under the terms of the Unit Agreement, we may be removed as unit operator upon default or failure to perform our duties by a vote of two or more working interest owners representing at least 80% of the working interest other than the interest held by us. In the event that we transfer our working interest ownership, we will be removed as unit operator.

Derivative Activity

We enter into derivative transactions with unaffiliated third parties with respect to oil and natural gas prices to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in oil and natural gas prices. All of our derivative transactions in place are NYMEX or Over the Counter (“OTC”) financial swaps and collars, which do not require option premiums. Our derivatives either swap floating prices for fixed prices indexed on NYMEX for oil and OTC for natural gas and NGLs or swap the NYMEX index price to an index that reflects a geographical area of production, in our case, the Waha natural gas and ANR-Oklahoma natural gas indices. Our NYMEX WTI oil collar contract combines a put option or “floor” with a call option or “ceiling”. We enter into derivative transactions with respect to LIBOR interest rates to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in LIBOR interest rates. All of our interest rate derivative transactions are LIBOR interest rate swaps, which do not require option premiums. Our derivatives swap floating LIBOR rates for fixed rates. All of our derivative counterparties are members of our bank group. For a more detailed discussion of our derivative activities, please read “Business — Oil and Natural Gas Derivative Activities,” “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Cash Flow from Operations” and “ Quantitative and Qualitative Disclosures About Market Risk.”

Title to Properties

Prior to completing an acquisition of producing oil and natural gas leases, we perform title reviews on significant leases and, depending on the materiality of properties, we may obtain a title opinion or review previously obtained title opinions. As a result, title opinions have been obtained on a significant portion of our 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.

We believe that we have satisfactory title to all of our material assets. Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry, we believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or will materially interfere with our use in the operation of our business. In addition, we believe that we have obtained sufficient rights-of-way grants and permits from public authorities and private parties for us to operate our business in all material respects as described in this document.

ITEM 3. *LEGAL PROCEEDINGS*

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any material legal proceedings. In addition, we are not aware of any legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

ITEM 4. *SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS*

None.

PART II

ITEM 5. *MARKET FOR REGISTRANTS UNITS, RELATED UNITHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES*

Our units, which were first offered and sold to the public on January 12, 2007, are listed on the NASDAQ Global Select Market under the symbol LGCY. As of March 3, 2009, there were 31,074,339 units outstanding, held by approximately 62 holders of record, including units held by our Founding Investors.

The following table presents the high and low sales prices for our units during the periods indicated (as reported on the NASDAQ Global Select Market) and the amount of the quarterly cash distributions we paid on each of our units with respect to such periods.

	Price Ranges		**Cash Distribution**	**Cash Distribution to**
2008	**High**	**Low**	**per Unit**	**General Partner**
First Quarter	$ 22.75	$ 17.95	$0.49	$ 8,972
Second Quarter	$ 25.17	$ 19.86	$0.52	$ 9,522
Third Quarter	$ 25.76	$ 14.00	$0.52	$ 9,522
Fourth Quarter	$ 17.43	$ 6.50	$0.52	$ 9,522(a)

	Price Ranges(b)		**Cash Distribution**	**Cash Distribution to**
2007	**High**	**Low**	**per Unit**	**General Partner**
First Quarter	$ 28.19	$ 18.90	$0.41	$ 7,508
Second Quarter	$ 30.42	$ 25.14	$0.42	$ 7,691
Third Quarter	$ 27.61	$ 18.50	$0.43	$ 7,874
Fourth Quarter	$ 24.57	$ 20.15	$0.45	$ 8,240

(a) This distribution was paid to our general partner concurrent with our distribution to unitholders on February 13, 2009.

(b)

Our units were not traded on an established public trading market prior to our initial public offering in January 2007.

Distribution Policy

We must distribute all of our cash on hand at the end of each quarter, less reserves established by our general partner. We refer to this cash as available cash, which is defined in our partnership agreement. We currently pay quarterly cash distributions of $0.52 per unit.

Recent Sales of Unregistered Securities

None not previously reported on a quarterly report on Form 10-Q or a current report on Form 8-K.

ITEM 6. *SELECTED FINANCIAL DATA*

We were formed in October 2005. Upon completion of our private equity offering and as a result of the related formation transactions on March 15, 2006, we acquired oil and natural gas properties and business operations from the Founding Investors and the three charitable foundations. Although we were the surviving entity for legal purposes, the formation transactions were treated as a purchase with Moriah Properties, Ltd. and its affiliates, or the Moriah Group, being considered, on a combined basis, as the acquiring entity for accounting purposes. As a result, Legacy Reserves LP (formerly the Moriah Group) applied the purchase method of accounting to the separable assets and the liabilities of the oil and natural gas properties acquired from the Founding Investors (other than the Moriah Group) and the charitable foundations. Our historical financial statements for periods prior to March 15, 2006 only reflect the accounts of the Moriah Group.

The following table shows selected historical financial and operating data for Legacy Reserves LP for the periods and as of the dates indicated. Through March 15, 2006, Legacys accompanying consolidated historical financial statements reflect the accounts of the Moriah Group, which includes the accounts of Moriah Resources, Inc. as the general partner of Moriah Properties, Ltd., Moriah Properties, Ltd., the oil and natural gas interests individually owned by Dale A. and Rita Brown until October 1, 2005 when those interests were transferred to DAB Resources, Ltd., DAB Resources, Ltd. and the accounts of MBN Properties LP. The Moriah Group consolidated MBN Properties LP as a variable interest entity with the portion of net income (loss) applicable to the other owners equity interests being eliminated through a non-controlling interest adjustment. Although MBN Management, LLC, the general partner of MBN Properties LP, is also a variable interest entity, it was accounted for by the Moriah Group using the equity method. From March 15, 2006, Legacys historical financial statements also include the results of operations of the oil and natural gas properties acquired from the other Founding Investors and the charitable foundations.

The selected historical financial data of the Moriah Group for the years ended December 31, 2005 and 2004 are derived from the audited consolidated financial statements of Legacy.

The operating results of the PITCO properties have been included from their September 14, 2005 acquisition date (Note 1 to the Consolidated Financial Statements). The operating results of the Farmer Field, South Justis and Kinder Morgan acquisition properties have been included from their acquisition dates in June and July 2006 (Note 4 to the Consolidated Financial Statements). The operating results of the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC, Summit, COP III and Pantwist acquisition properties have been included from their acquisition dates (Note 4 to the Consolidated Financial Statements).

You should read the following selected financial data in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and Legacys financial statements and related notes included elsewhere in this annual report on Form 10-K.

Years Ended December 31,

	2008(a)	2007(b)	2006(c)	2005(d)	2004
		(In thousands, except per unit data)			
Statement of Operations Data:					
Revenues:					
Oil sales	$ 157,973	$ 83,301	$ 45,351	$ 18,225	$ 10,998
Natural gas liquids sales	15,862	7,502	—	—	
Natural gas sales	41,589	21,433	14,446	7,318	3,945
Total Revenues	215,424	112,236	59,797	25,543	14,943
Expenses:					
Oil and natural gas production	52,004	27,129	15,938	6,376	4,345
Production and other taxes	12,712	7,889	3,746	1,636	928
General and administrative	11,396	8,392	3,691	1,354	732
Depletion, depreciation, amortization and accretion	63,324	28,415	18,395	2,291	883
Impairment of long-lived assets	76,942	3,204	16,113	—	
Loss on disposal of assets	602	527	42	20	
Total expenses	216,980	75,556	57,925	11,677	6,888
Operating income (loss)	(1,556)	36,680	1,872	13,866	8,055
Other income (expense):					
Interest income	93	321	130	185	419
Interest expense	(21,153)	(7,118)	(6,645)	(1,584)	(213
Gain on sale of partnership investment	—	—	—	—	1,292
Equity in income (loss) of partnerships	108	77	(318)	(495)	183
Realized and unrealized gain (loss) on oil, NGL and natural gas swaps and collars	176,943	(85,156)	9,289	(6,159)	(633
Other	116	(129)	29	46	92
Income (loss) before income taxes	154,551	(55,325)	4,357	5,859	9,195
Income taxes	(48)	(337)	—	—	
Income (loss) from continuing operations	$ 154,503	$ (55,662)	$ 4,357	$ 5,859	$ 9,195
Earnings (loss) from continuing operations per unit					
Basic and fully diluted	$ 5.05	$ (2.13)	$ 0.26	$ 0.62	$ 0.97
Distributions per unit(e)	$ 1.98	$ 1.67	$ 0.8974		

			Years Ended December 31,		
	2008(a)	2007(b)	2006(c)	2005(d)	2004
			(In thousands)		
Cash Flow Data:					
Net cash provided by operating activities	$ 140,985	$ 57,147	$ 29,590	$ 14,409	$ 8,586
Net cash provided by (used in) investing activities	$ (258,035)	$ (196,505)	$ (62,505)	$ (68,965)	$ 1,023
Net cash provided by (used in) financing activities	$ 109,946	$ 147,900	$ 32,022	$ 55,742	$ (8,958
Capital expenditures	$ 217,980	$ 196,702	$ 56,150	$ 66,915	$ 3,325

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			Historical Year Ended December 31,		
	2008(a)	2007(b)	2006(c)	2005(d)	2004
			(In thousands)		
Balance Sheet Data					

Cash and cash equivalents	$ 2,500	$ 9,604	$ 1,062	$ 1,955	$ 769
Other current assets	78,437	23,954	17,159	6,316	5,799
Oil and natural gas properties, net of accumulated depletion, depreciation and amortization	613,032	440,180	247,580	77,172	12,224
Other assets	89,103	7,840	7,567	1,499	
Total assets	$ 783,072	$ 481,578	$ 273,368	$ 86,942	$ 18,792
Current liabilities	$ 57,006	$ 43,457	$ 10,834	$ 4,562	$ 4,898
Long term debt	282,000	110,000	115,800	52,473	
Other long-term liabilities	63,433	72,391	7,945	19,998	1,872
Unitholders equity	380,633	255,730	138,789	9,909	12,022
Total liabilities and unitholders equity	$ 783,072	$ 481,578	$ 273,368	$ 86,942	$ 18,792

(a) Reflects Legacys purchase of the oil and natural gas properties acquired in the COP III and Pantwist Acquisitions as of the date of their respective acquisitions. Consequently, the operations of these acquired properties are only included for the period from the closing dates of such acquisitions through December 31, 2008.

(b) Reflects Legacys purchase of the oil and natural gas properties acquired in the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC and Summit Acquisitions as of the date of their respective acquisitions. Consequently, the operations of these acquired properties are only included for the period from the closing dates of such acquisitions through December 31, 2007.

(c) Reflects Legacys purchase of the oil and natural gas properties acquired in the March 15, 2006 formation transactions and the South Justis, Farmer Field and Kinder Morgan acquisitions in June and July 2006. Consequently, the operations of these acquired properties are only included for the period from the closing dates of such acquisitions through December 31, 2006.

(d) Reflects the Moriah Groups purchase of the PITCO properties on September 14, 2005. Consequently, the operations of the PITCO properties are only included for the period following the date of acquisition.

(e) Amounts not presented for years prior to 2006 since they would not be meaningful.

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ITEM 7. *MANAGEMENTS DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS*

The following discussion and analysis should be read in conjunction with the Selected Historical Consolidated Financial Data and the accompanying financial statements and related notes included elsewhere in this annual report on Form 10-K. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for natural gas, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this report, particularly in Risk Factors and Cautionary Statement Regarding Forward-Looking Information, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

Overview

We were formed in October 2005. Upon completion of our private equity offering and as a result of the related formation transactions on March 15, 2006, we acquired oil and natural gas properties and business operations from our Founding Investors and three charitable foundations (Legacy Formation). Although we were the surviving entity for legal purposes, the formation transactions were treated as a purchase with the Moriah Group being considered, on a combined basis, as the acquiring entity for accounting purposes. Therefore, the accounts reflected in our historical financial statements prior to March 15, 2006 are those of the Moriah Group.

The Moriah Group owned and operated oil and natural gas producing properties located primarily in the Permian Basin of West Texas and southeast New Mexico. The Moriah Group included the accounts of Moriah Resources, Inc. as the general partner of Moriah Properties, Ltd., the oil and natural gas interests individually owned by Dale A. and Rita Brown until October 1, 2005 when those interests were transferred to DAB Resources, Ltd., DAB Resources, Ltd. and the accounts of MBN Properties LP. The Moriah Group consolidated MBN Properties LP as a variable interest entity with the portion of net income (loss) applicable to the other owners equity interests eliminated through a non-controlling interest adjustment. Although MBN Management, LLC, the general partner of MBN Properties LP, is also a variable interest entity, it was accounted for by the Moriah Group using the equity method.

Because of our rapid growth through acquisitions and development of properties, historical results of operations and period-to-period comparisons of these results and certain financial data may not be meaningful or indicative of future results. Since the PITCO properties were not acquired until September 14, 2005, the results of operations only include the operating results for the PITCO properties from September 14, 2005. The operating results of the properties acquired in the formation transactions are included in the results of operations from March 15, 2006, the operating results of the South Justis Unit properties and the Farmer Field properties acquired on June 29, 2006 have been included from July 1, 2006 and the operating results of the Kinder Morgan properties have been included from August 1, 2006. The operating results of the properties acquired in the Binger Acquisition are included in the results of operations from April 16, 2007, the operating results of the Ameristate Acquisition have been included from May 1, 2007, the operating results of the TSF Acquisition have been included from May 25, 2007, the operating results of the Raven Shenandoah Acquisition have been included from May 31, 2007, the operating results of the Raven OBO Acquisition have been included from August 3, 2007, the operating results from the TOC and Summit Acquisitions have been included from October 1, 2007, the operating results from the COP III Acquisition have been included from April 30, 2008 and the operating results from the Pantwist Acquisition have been included from October 1, 2008.

Acquisitions have been financed with a combination of proceeds from bank borrowings and issuances of units and cash flow from operations. Post-acquisition activities are focused on evaluating and exploiting the acquired properties and evaluating potential add-on acquisitions.

Our revenues, cash flow from operations and future growth depend substantially on factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. Oil and natural gas prices historically have been volatile and may fluctuate widely in the future.

Sustained periods of low prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce and our access to capital.

Outlook. The current global economic environment has reduced the demand for oil and natural gas and resulted in a significant decrease of commodity prices. In addition, financial and credit markets have deteriorated, virtually shutting down access to public financial markets and significantly reducing the availability of credit. We cannot predict future commodity prices nor when and whether credit conditions will ease and financial markets will become available again. Based on the drastic decrease in commodity prices in the third and fourth quarters of 2008, we expect a challenging 2009. Crude oil prices declined from a high of $145.31 per Bbl in July 2008 to $44.60 per Bbl at December 31, 2008. Similarly, natural gas prices declined from a high of $13.58 per MMbtu in July of 2008 to $5.62 per MMbtu at December 31, 2008. Primarily as a result of the drastic decline in commodity prices, the present value or standardized measure of our proved reserves was revised downward from $690.5 million as of December 31, 2007 to $235.0 million as of December 31, 2008, and we had to recognize an impairment of $76.9 million in the value of our oil and gas properties. The drastic decline in commodity prices is also primarily responsible for a decrease in operating income from $29.8 million in the third quarter of 2008 to an operating loss of $90.2 million, including impairment of $76.5 million, in the fourth quarter of 2008. Though a sustained period of reduced commodity prices will have an adverse effect on our operating income in future periods resulting in decreased revenues and higher depletion rates, we do not anticipate future operating losses, if any, to be at the level recorded in the fourth quarter of 2008 as we have fully impaired a majority of our properties that are at risk under the current price environment. Based on the significant decline in commodity prices and the resulting change in our operating results, in the fourth quarter of 2008, approximately 50% of our drilling projects or proved undeveloped reserves became uneconomic. As a result, we reduced our 2009 capital expenditure budget to $20.0 million from $28.6 million in 2008.

We face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and natural gas production from a given well or formation decreases. We attempt to overcome this natural decline by utilizing multiple types of recovery techniques such as secondary (waterflood) and tertiary (CO_2 and nitrogen) recovery methods to re-pressure the reservoir and recover additional oil, drilling to find additional reserves, re-stimulating existing wells, improving artificial lift 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 adding reserves through acquisitions and development projects. Our ability to add reserves through acquisitions and development projects is dependent upon many factors including our ability to raise capital, obtain regulatory approvals and contract drilling rigs and personnel.

Our revenues are highly sensitive to changes in oil and natural gas prices and to levels of production. As set forth under Cash Flow from Operations below, we have entered into oil, NGL and natural gas derivatives designed to mitigate the effects of price fluctuations covering a significant portion of our expected production, which allows us to mitigate, but not eliminate, oil and natural gas price risk. We continuously conduct financial sensitivity analyses to assess the effect of changes in pricing and production. These analyses allow us to determine how changes in oil and natural gas prices will affect our ability to execute our capital investment programs and to meet future financial obligations. Further, the financial analyses allow us to monitor any impact such changes in oil and natural gas prices may have on the value of our proved reserves and their impact on any re-determination to our borrowing base under our revolving credit facility.

Legacy does not specifically designate derivative instruments as cash flow hedges; therefore, the mark-to-market adjustment reflecting the unrealized gain or loss associated with these instruments is recorded in current earnings.

Production and Operating Costs Reporting

We strive to increase our production levels to maximize our revenue and cash available for distribution. Additionally, we continuously monitor our operations to ensure that we are incurring operating costs at the optimal level. Accordingly, we continuously monitor our production and operating costs per well to determine if any wells or properties should be shut-in, re-completed or sold.

Such costs include, but are not limited to, the cost of electricity to lift produced fluids, chemicals to treat wells, field personnel to monitor the wells, well repair expenses to restore production, well workover expenses intended to increase production and ad valorem taxes. We incur and separately report severance taxes paid to the states and counties in which our properties are located. These taxes are reported as production taxes and are a percentage of oil and natural gas revenue. Ad valorem taxes are a percentage of property valuation. Gathering and transportation costs are generally borne by the purchasers of our oil and natural gas as the price paid for our products reflects these costs. We do not consider royalties paid to mineral owners as an expense as we deduct hydrocarbon volumes owned by mineral owners from reported hydrocarbon sales volumes.

Operating Data

The following table sets forth our selected financial and operating data for the periods indicated.

	Year Ended December 31,		
	2008(a)	2007(b)	2006(c)
	(In thousands, except per unit data)		
Revenues:			
Oil sales	$ 157,973	$ 83,301	$ 45,351
Natural gas liquid sales	15,862	7,502	—
Natural gas sales	41,589	21,433	14,446
Total revenue	$ 215,424	$ 112,236	$ 59,797
Expenses:			