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 registrant's 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 registrant's 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

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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 managements 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 managements 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, Legacys 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 RCRAs 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 Earths 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 Acts 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 FERCs 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

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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 operator's 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 partner s 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.

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 Legacy's 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.

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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 Legacy’s 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 Legacy’s 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 Legacy’s 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 Group’s 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.

ITEM 7. *MANAGEMENT’S 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.

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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.

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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:			
Oil and natural gas production	$ 52,004	$ 27,129	$ 15,938
Production and other taxes	$ 12,712	$ 7,889	$ 3,746
General and administrative	$ 11,396	$ 8,392	$ 3,691
Depletion, depreciation, amortization and accretion	$ 63,324	$ 28,415	$ 18,395
Realized swap settlements:			
Realized loss on oil swaps	$ (38,185)	$ (3,627)	$ (6,667)
Realized loss on natural gas liquid swaps	$ (3,025)	$ (619)	$ —
Realized gain on natural gas swaps	$ 977	$ 4,457	$ 6,405
Production:			
Oil — barrels	1,660	1,179	749
Natural gas liquids — gallons	12,977	5,295	—
Natural gas — Mcf	4,838	3,052	2,200
Total (MBoe)	2,775	1,814	1,116
Average daily production (Boe/d)	7,582	4,970	3,058
Average sales price per unit (excluding swaps):			
Oil price per barrel	$ 95.16	$ 70.65	$ 60.55
Natural gas liquid price per gallon	$ 1.22	$ 1.42	$ —
Natural gas price 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 price per barrel	$ 72.16	$ 67.58	$ 51.65(e)
Natural gas liquid price per gallon	$ 0.99	$ 1.30	$ —
Natural gas price per Mcf	$ 8.80	$ 8.48	$ 9.48
Combined (per Boe)	$ 63.13	$ 61.99	$ 53.35(e)
NYMEX oil index prices per barrel:			
Beginning of Period	$ 95.98	$ 61.05	$ 61.04
End of Period	$ 44.60	$ 95.98	$ 61.05
NYMEX gas index prices per Mcf:			
Beginning of Period	$ 7.48	$ 6.30	$ 11.25
End of Period	$ 5.62	$ 7.48	$ 6.30
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, amortization and accretion	$ 22.82	$ 15.66	$ 16.48

(a) Reflects the production and operating results of the oil and natural gas properties acquired in the COP III and Pantwist Acquisitions 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.

(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 Legacy’s oil and 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.

Results of Operations

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

Legacys revenues from the sale of oil were $158.0 million and $83.3 million for the years ended December 31, 2008 and 2007, respectively. Legacys revenues from the sale of NGLs were $15.9 million and $7.5 million for the years ended December 31, 2008 and 2007, respectively. Legacys revenues from the sale of natural gas were $41.6 million and $21.4 million for the years ended December 31, 2008 and 2007, respectively. The $74.7 million increase in oil revenues reflects an increase in oil production of 481 MBbls (41%) due primarily to Legacys purchase of the oil and natural gas properties acquired in the COP III and Pantwist Acquisitions, a full year of production from the 2007 acquisitions, our development activities and several additional acquisitions, which are both individually and collectively immaterial. While the realized price increased $24.51 per Bbl during the year ended December 31, 2008, we had a significant decline in realized oil prices during the fourth quarter of 2008. The $8.4 million increase in NGL revenues reflects an increase in NGL production of 7,682 MMGal (145%) due to Legacys purchase of oil and natural gas properties acquired in the COP III and Pantwist Acquisitions, a full year of production from the 2007 acquisitions, our development activities and several additional acquisitions, which are both individually and collectively immaterial, and a full year of production from 2007 acquisition properties. The $20.2 million increase in natural gas revenues reflects an increase in natural gas production of approximately 1,786 MMcf (59%) due primarily to Legacys purchase of oil and natural gas properties in the COP III and Pantwist Acquisitions, a full year of production from the 2007 acquisitions, our development activities and several additional acquisitions, which are both individually and collectively immaterial, while the realized price per Mcf increased $1.58 per Mcf.

For the year ended December 31, 2008, Legacy recorded $176.9 million of net gains on oil and natural gas swaps and collars comprised of realized losses of $40.2 million from net cash settlements of oil, NGL and natural gas swap contracts and net unrealized gains of $217.1 million. Legacy had unrealized net gains from its oil swaps because the fixed prices of its oil swap contracts were above the NYMEX index prices at December 31, 2008. As a point of reference, the NYMEX price for light sweet crude oil for the near-month close at December 31, 2008 was $44.60 per Bbl, a price which is less than the average contract prices of Legacys outstanding oil swap contracts of $83.53 per Bbl. Legacy had unrealized net gains from its natural gas and NGL swaps because the fixed prices of its natural gas and NGL swap contracts were above the NYMEX index prices at December 31, 2008. As a point of reference, the NYMEX price for natural gas for the near-month close at December 31, 2008 was $5.62 per MMbtu, a price which is less than the average contract prices of Legacys outstanding natural gas swap contracts of $7.99 per MMbtu. For the year ended December 31, 2007, Legacy recorded $80.1 million of net losses on oil swaps comprised of a realized loss of $3.6 million from net cash settlements of oil swap contracts and a net unrealized loss of $76.5 million. For the year ended December 31, 2007, Legacy recorded $3.8 million of net losses on NGL swaps comprised of a realized loss of $0.6 million from net cash settlements of NGL swap contracts and a net unrealized loss of $3.2 million. For the year ended December 31, 2007, Legacy recorded $1.2 million of net losses on natural gas swaps comprised of a realized gain of $4.5 million from net cash settlements of natural gas swap contracts and a net unrealized loss of $5.7 million. Unrealized gains and losses represent a current period mark-to-market adjustment for commodity derivatives which will be settled in future periods.

Legacy's oil and natural gas production expenses, excluding production and other taxes, increased to $52.0 million ($18.74 per Boe) for the year ended December 31, 2008, from $27.1 million ($14.96 per Boe) for the year ended December 31, 2007. Production expenses increased primarily because of (i) $6.0 million related to the COP III Acquisition, (ii) $0.4 million related to the Pantwist Acquisition, (iii) $7.1 million related to several immaterial acquisitions and (iv) increased production and increased cost of services and certain operating costs that are directly related to the higher commodity prices experienced during the year ended December 31, 2008, including the cost of electricity, which powers artificial lift equipment and pumps involved in the production of oil, and the higher level of industry activity stimulated by higher oil and natural gas prices.

Legacy's production and other taxes were $12.7 million and $7.9 million for the years ended December 31, 2008 and 2007, respectively. Production and other taxes increased primarily because of (i) approximately $0.7 million of taxes related to the COP III Acquisition, (ii) $1.9 million of taxes related to several immaterial acquisitions and (iii) higher realized commodity prices in the 2008 period as production taxes are assessed as a percentage of revenue.

Legacy's general and administrative expenses were $11.4 million and $8.4 million for the years ended December 31, 2008 and 2007, respectively. General and administrative expenses increased approximately $3.0 million between periods primarily due to increased employee costs related to business expansion.

Legacy's depletion, depreciation, amortization and accretion expense, or DD&A, was $63.3 million and $28.4 million for the years ended December 31, 2008 and 2007, respectively, reflecting primarily the significant decrease in oil and natural gas prices during the fourth quarter of 2008 which resulted in a significant downward revision in proved reserve volumes causing an increase in our depletion rates. As a point of reference, our depletion rate per BOE for the year ended December 31, 2008 was $22.82 compared to $15.66 for the year ended December 31, 2007.

Impairment expense was $76.9 million and $3.2 million for the years ended December 31, 2008 and 2007, respectively. In 2008 Legacy recognized impairment expense in 101 separate producing fields, due primarily to significant declines in oil and natural gas prices in the fourth quarter of 2008 resulting in reduced future expected cash flows on these fields. In 2007 Legacy recognized impairment expense in 43 separate producing fields, due primarily to performance decline in properties within these fields.

Legacy recorded interest income of $93,010 for the year ended December 31, 2008 and $320,968 for the year ended December 31, 2007. The decrease of $227,958 is a result of lower average interest rates received during the year ended December 31, 2008.

Interest expense was $21.2 million and $7.1 million for the years ended December 31, 2008 and 2007, respectively, reflecting higher average borrowings during the year ended December 31, 2008 and a mark-to-market adjustment related to interest rate swaps of approximately $9.0 million.

Legacy recorded equity in income of partnership of $107,795 and $77,144 for the years ended December 31, 2008 and 2007, respectively, related to its non-controlling interest in Binger Operations LP ("BOL"). This income is primarily derived from Legacy's non-controlling interest in BOL's less than 1% interest in the Binger Unit. The increase of $30,651 is a result of higher average realized oil and natural gas prices for the year ended December 31, 2008.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

Legacy's revenues from the sale of oil were $83.3 million and $45.4 million for the years ended December 31, 2007 and 2006, respectively. Legacy's revenues from the sale of NGL's were $7.5 million for the year ended December 31, 2007. Legacy had no revenues from NGL sales for the year ended December 31, 2006. Legacy's revenues from the sale of natural gas were $21.4 million and $14.4 million for the years ended December 31, 2007 and 2006, respectively. The $37.9 million increase in oil revenues reflects an increase in oil production of

430 MBbls (57%) due primarily to Legacy□s purchase of the oil and natural gas properties acquired in the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC and Summit Acquisitions while the realized price increased $10.10 per Bbl. The $7.5 million increase in NGL revenues is due to Legacy□s purchase of oil and natural gas properties acquired in the Binger, Ameristate, Raven Shenandoah, Raven OBO and TOC Acquisitions.

The $7.0 million increase in natural gas revenues reflects an increase in natural gas production of approximately 852 MMcf (39%) due primarily to Legacy□s purchase of oil and natural gas properties in the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC and Summit Acquisitions while the realized price per Mcf increased $0.45 per Mcf.

For the year ended December 31, 2007, Legacy recorded $85.2 million of net losses on oil and natural gas swaps comprised of realized gains of $0.2 million from net cash settlements of oil, NGL and natural gas swap contracts and net unrealized losses of $85.4 million. Legacy had unrealized net losses from its oil swaps because the fixed price of its oil swap contracts were below the NYMEX index prices at December 31, 2007. As a point of reference, the NYMEX price for light sweet crude oil for the near-month close at December 31, 2007 was $95.98 per Bbl, a price which is greater than the average contract prices of Legacy□s outstanding oil swap contracts. Legacy had unrealized net losses from its NGL swaps because the fixed price of its NGL swap contracts were below the NYMEX index prices at December 31, 2007. Legacy had unrealized net losses from its natural gas swaps because the fixed prices of its natural gas swap contracts were below the NYMEX index prices at December 31, 2007. As a point of reference, the NYMEX price for natural gas for the near-month close at December 31, 2007 was $7.48 per MMbtu, a price which is greater than the average contract prices of Legacy□s outstanding natural gas swap contracts. For the year ended December 31, 2006, Legacy recorded $2.3 million of net losses on oil swaps comprised of a realized loss of $6.7 million from net cash settlements of oil swap contracts and a net unrealized gain of $4.3 million. For the year ended December 31, 2006, Legacy recorded $11.6 million of net gains on gas swaps comprised of a realized gain of $6.4 million from net cash settlements of gas swap contracts and a net unrealized gain of $5.2 million. Unrealized gains and losses represent a current period mark-to-market adjustment for commodity derivatives which will be settled in future periods.

Legacy□s oil and natural gas production expenses, excluding production and other taxes, increased to $27.1 million ($14.96 per Boe) for the year ended December 31, 2007, from $15.9 million ($14.28 per Boe) for the year ended December 31, 2006. Production expenses increased primarily because of (i) $2.9 million related to the Binger Acquisition, (ii) $3.4 million related to the Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC and Summit Acquisitions and (iii) increased production and increased cost of services and certain operating costs that are directly related to higher commodity prices, particularly the cost of electricity, which powers artificial lift equipment and pumps involved in the production of oil.

Legacy□s production and other taxes were $7.9 million and $3.7 million for the years ended December 31, 2007 and 2006, respectively. Production and other taxes increased primarily because of (i) approximately $1.0 million of taxes related to the Binger Acquisition, (ii) $1.0 million of taxes related to the Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC and Summit Acquisitions and (iii) higher commodity prices in the 2007 period.

Legacy□s general and administrative expenses were $8.4 million and $3.7 million for the years ended December 31, 2007 and 2006, respectively. General and administrative expenses increased approximately $4.7 million between periods primarily due to (i) increased employee costs related to business expansion, (ii) $1.4 million of costs incurred in connection with awards granted under the LTIP due to a $1.1 million non-cash expense related to the change in estimated fair value of the unit-based compensation liability related to unit options, unit grants, phantom unit grants and unit appreciation rights and $0.3 million of cash payments to employees exercising unit options and (iii) approximately $0.5 million of costs incurred in connection with the preparation of the 2006 U.S. federal income tax return and related form K-1□s.

Legacy□s depletion, depreciation, amortization and accretion expense, or DD&A, was $28.4 million and $18.4 million for the years ended December 31, 2007 and 2006, respectively, reflecting primarily (i) $6.3 million of DD&A related to the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC and Summit Acquisitions, (ii) $1.1 million to the Legacy Formation and (iii) $1.6 million related to the South Justis, Farmer Field, and Kinder Morgan Acquisitions.

Impairment expense was $3.2 million and $16.1 million for the years ended December 31, 2007 and 2006, respectively. In 2007 Legacy recognized impairment expense in 43 separate producing fields, due primarily to performance decline in properties within these fields. In 2006 Legacy recognized impairment expense in 41 separate producing fields, due primarily to the decline in oil and natural gas prices from the dates at which the purchase prices for the PITCO acquisition and the Legacy Formation were allocated among the purchased

properties. As a point of reference, the NYMEX closing price for oil was $61.05 per Bbl at December 31, 2006, as compared to $66.63 per Bbl on March 31, 2006 at the time of the Legacy Formation and $66.24 per Bbl on September 30, 2005 at the time of the PITCO acquisition. As a point of reference, the NYMEX closing price for natural gas was $6.30 per MMbtu at December 31, 2006, as compared to $7.21 per MMbtu on March 31, 2006 at the time of the Legacy Formation and $13.92 per MMbtu on September 30, 2005 at the time of the PITCO acquisition.

Legacy recorded interest income of $320,968 for the year ended December 31, 2007 and $129,712 for the year ended December 31, 2006. The increase of $191,256 is a result of higher average cash balances during the year ended December 31, 2007.

Interest expense was $7.1 million and $6.6 million for the years ended December 31, 2007 and 2006, respectively, reflecting higher average borrowings during the year ended December 31, 2007 and a mark-to-market adjustment related to interest rate swaps of approximately $1.5 million.

Legacy recorded equity in income of partnership of $77,144 for the year ended December 31, 2007 and a loss of $317,788 for the year ended December 31, 2006. In 2007, Legacy recorded equity in income of partnership related to its non-controlling interest in Binger Operations LP (BOL). This income is primarily derived from BOLs less than 1% interest in the Binger Unit. In 2006, Legacy recorded equity in loss of partnership related to its investment in MBN Management, LLC, which was formed in July, 2005. Legacy did not acquire any interest in MBN Management, LLC as part of the Legacy Formation. Accordingly, such losses will not be incurred in the future.

Capital Resources and Liquidity

Legacys primary sources of capital and liquidity have been proceeds from bank borrowings, cash flow from operations, its private offering in March 2006, its initial public offering in January 2007 and its private offering in November 2007. To date, Legacys primary use of capital has been for the acquisition and development of oil and natural gas properties. During the year ended December 31, 2006, Legacy cancelled (before their original settlement date) a portion of its NYMEX oil swaps covering periods in 2007 and 2008 and realized a loss of $4.0 million. As a result, Legacys working capital was reduced by $4.0 million.

As we pursue growth, we continually monitor the capital resources available to us to meet our future financial obligations and planned capital expenditures. Our future success in growing reserves and production will be highly dependent on capital resources available to us and our success in acquiring and developing additional hydrocarbon reserves. We actively review acquisition opportunities on an ongoing basis. If we were to make significant additional acquisitions for cash, we would need to borrow additional amounts under our revolving credit facility, if available, or obtain additional debt or equity financing. Our revolving credit facility imposes certain restrictions on our ability to obtain additional debt financing. Further, our existing credit facility matures on March 15, 2010. Due to the recent severe disruptions in the financial markets, existing lenders under our revolving credit facility may or may not be able to enter into a replacement credit facility with us and as a result, all amounts outstanding under our existing revolving credit facility on March 15, 2010 would become immediately due and payable. Further, any replacement facility may impose less attractive terms and more severe restrictive covenants on us, and the credit amounts available under such replacement facility may be significantly lower. Based upon current oil and natural gas price expectations for the year ending December 31, 2009, we anticipate that our cash on hand, cash flow from operations and available borrowing capacity under our revolving credit facility will provide us sufficient working capital to meet our planned capital expenditures of $20.0 million and planned cash distributions of $64.6 million, which reflect the $16.16 million of distributions paid in the first quarter of 2009 and $16.16 million of planned distributions during each of the second, third and fourth quarters of 2009. Our board of directors determines our distribution each quarter and there is no guarantee that the board will maintain our current quarterly distribution rate of $0.52 per unit. Please read

Financing Activities Our Revolving Credit Facility.

Cash Flow from Operations

Legacys net cash provided by operating activities was $141 million and $57.1 million for the year ended December 31, 2008 and 2007, respectively, with the 2008 period being favorably impacted by higher sales volumes and higher realized oil and natural gas prices, partially offset by higher expenses.

Legacys net cash provided by operating activities was $57.1 million and $29.6 million for the years ended December 31, 2007 and 2006, respectively, with the 2007 period being favorably impacted by higher sales volumes and higher realized oil and natural gas prices, partially offset by higher expenses.

Our cash flow from operations is subject to many variables, the most significant of which is the volatility of oil, NGL and natural gas prices. Oil, NGL and natural gas prices are determined primarily by prevailing market conditions, which are dependent on regional and worldwide economic activity, weather and other factors beyond our control. Our future cash flow from operations will depend on our ability to maintain and increase production through acquisitions and development projects, as well as the prices of oil, NGLs and natural gas.

Investing Activities

Legacys cash capital expenditures were $216.4 million for the year ended December 31, 2008. The total includes $52.2 million and $40.6 million for the purchase of producing oil and natural gas properties in the COP III and Pantwist Acquisitions, respectively. The remaining balance was expended in several smaller individual acquisitions and development projects.

Legacys capital expenditures were $196.0 million and $55.9 million for the years ended December 31, 2007 and 2006, respectively. The total for the year ended December 31, 2007 includes $28.5 million, $5.2 million, $14.8 million, $13.5 million, $20.9 million, $62.1 million and $13.5 million for the purchase of producing oil and natural gas properties in the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC and Summit Acquisitions, respectively. The balance was expended in smaller individual acquisitions and development projects.

We currently anticipate that our development capital budget, which predominantly consists of drilling, re-completion and well stimulation projects, will be $20.0 million for the year ending December 31, 2009. Our borrowing capacity under our revolving credit facility is $110 million as of March 2, 2009. The amount and timing of our capital expenditures is largely discretionary and within our control, with the exception of certain projects managed by other operators. If oil and natural gas prices decline below levels we deem acceptable, we may defer a portion of our planned capital expenditures until later periods. Accordingly, we routinely monitor and adjust our capital expenditures in response to changes in oil and natural gas prices, drilling and acquisition costs, industry conditions and internally generated cash flow. Matters outside our control that could affect the timing of our capital expenditures include obtaining required permits and approvals in a timely manner and the availability of rigs and labor crews. Based upon managements current oil and natural gas price expectations for the year ending December 31, 2009, we anticipate that we will have sufficient sources of working capital, including our cash flow from operations and available borrowing capacity under our revolving credit facility, to meet our cash obligations including our planned capital expenditures of $20.0 million and planned cash distributions of $64.6 million during the year ending December 31, 2009. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures or cash distributions.

We enter into oil, NGL and natural gas derivatives to reduce the impact of oil, NGL and natural gas price volatility on our cash flow. Currently, we use swaps and collars to offset price volatility on NYMEX oil, NGL and Waha and ANR-Oklahoma natural gas prices, which do not include the additional net discount that we typically realize in the Permian Basin. At December 31, 2008, we had in place oil, NGL and natural gas swaps covering significant portions of our estimated 2009 through 2013 oil, NGL and natural gas production. As of March 2, 2009 we had derivatives covering approximately 70% of our expected oil, NGL and natural gas production for 2009. As of March 2, 2009 we had also entered into derivative contracts covering over 50% on average of our expected oil, NGL and natural gas production for 2010 through 2013 from existing total proved reserves.

By removing the price volatility on our cash flows from a significant portion of our oil, NGL and natural gas production, we have mitigated, but not eliminated, the potential effects of changing prices on our cash flow for those periods. While mitigating negative effects of falling commodity prices, these derivative contracts also limit the benefits we would receive from increases in commodity prices. It is our policy to enter into derivative contracts only with counterparties that are major, creditworthy financial institutions deemed by management as competent and competitive market makers. In addition, these counterparties are members of our revolving credit facility, which allows us to avoid margin calls. However, due to the recent severe disruptions in the financial markets, we can no longer predict whether any counterparty will meet its obligations under our derivative contracts. Due to this uncertainty, we routinely monitor the creditworthiness of our counterparties.

The following tables summarize, for the periods indicated, our oil and natural gas swaps as of March 2, 2009 in place through December 31, 2013. We use swaps as our mechanism for hedging commodity prices whereby we pay the counterparty floating prices and receive fixed prices from the counterparty, which serves to hedge the floating prices we are paid by purchasers of our oil and natural gas. These transactions are settled based upon the monthly average closing price of the front-month NYMEX WTI oil contract price of oil at Cushing, Oklahoma, and NYMEX Henry Hub, West Texas Waha and ANR-Oklahoma prices of natural gas on the average of the three final trading days of the month and settlement occurs on the fifth day of the production month.

Calendar Year	Annual Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
2009	1,488,969	$82.82	$61.05 - $140.00
2010	1,397,973	$82.37	$60.15 - $140.00
2011	1,155,712	$88.07	$67.33 - $140.00
2012	969,812	$81.28	$67.72 - $109.20
2013	240,000	$82.00	$82.00

Calendar Year	Annual Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
2009	3,167,142	$8.06	$6.85 - $10.18
2010	2,840,859	$7.87	$6.85 - $ 9.73
2011	2,127,316	$8.01	$6.85 - $ 8.70
2012	1,579,736	$8.02	$6.85 - $ 8.70

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. The basis swaps thereby provide a better match between our natural gas sales and the settlement payments on our natural gas swaps. The following table summarizes, for the periods indicated, our NYMEX-Waha basis swaps as of March 2, 2009 in place through December 31, 2010:

Calendar Year	Annual Volumes (MMBtu)	Basis Differential per Mcf
2009	1,320,000	$(0.68)
2010	1,200,000	$(0.57)

In December of 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 Texas Panhandle and Oklahoma natural gas sales follow ANR-Oklahoma more closely than NYMEX. The following table summarizes, for the periods indicated, our NYMEX-ANR-Oklahoma basis swaps as of March 2, 2009 in place through December 31, 2010:

Calendar Year	Annual Volumes (MMBtu)	Basis Differential per Mcf
2009	480,000	$(1.09)
2010	480,000	$(0.87)

On March 30, 2007, we entered into NGL swaps to hedge the impact of volatility in the spot prices of NGLs. On September 7, 2007, we entered into additional NGL swaps. These swaps hedge the spot prices for ethane, propane, iso-butane, normal butane and natural gasoline tracked on the Mont Belvieu, Non-Tet OPIS exchange. The following table summarizes, for the periods indicated, fixed prices to be received under our Mont Belvieu, Non-Tet OPIS NGL swaps as of March 2, 2009 in place through December 31, 2009, and reflects the volume-weighted average price of the NGL components hedged.

Calendar Year	Annual Volumes (Gal)	Price per Gal
2009	2,265,480	$1.15

On June 24, 2008, Legacy entered into a NYMEX West Texas Intermediate oil derivative collar contract that combines a put option or "floor" with a call option or "ceiling". The following table summarizes the oil collar contract currently in place as of March 2, 2009, through December 31, 2012:

Calendar Year	Annual Volumes (Bbls)	Average Floor	Average Ceiling
2009	75,400	$120.00	$156.30
2010	71,800	$120.00	$156.30
2011	68,300	$120.00	$156.30
2012	65,100	$120.00	$156.30

The following table details the commodity derivative assets (liabilities), by commodity, as of December 31, 2008 and 2007:

	Oil Swaps	Oil Collar	Natural Gas Swaps	Natural Gas Basis Swaps	NGL Swaps	Total
			(In thousands)			
Balance December 31, 2007	$ (78,089)	$ —	$ (510)	$ (444)	$ (3,228)	$ (82,271)
Balance December 31, 2008	$ 102,454	$ 15,366	$ 15,339	$ 437	$ 1,309	$ 134,905

The following table details the commodity derivative income (expense) activities, by commodity, for the year ended December 31,2008:

	Oil Swaps	Oil Collar	Natural Gas Swaps	Natural Gas Basis Swaps	NGL Swaps	Total
			(In thousands)			
Realized gain (loss) on cash settlements	$ (38,185)	$ —	$ 150	$ 827	$ (3,025)	$ (40,233)
Unrealized gain on mark-to-market of derivatives existing as of January 1, 2008	96,908	—	7,837	849	4,537	110,131
Unrealized gain on mark-to-market of derivatives entered during 2008	83,635	15,366	8,012	32	—	107,045
Realized and unrealzed gain on derivatives	$ 142,358	$ 15,366	$ 15,999	$ 1,708	$ 1,512	$ 176,943

Financing Activities

Our Revolving Credit Facility

At the closing of our private equity offering on March 15, 2006, we entered into a four-year revolving credit facility with BNP Paribas as administrative agent. Borrowings under the facility are due on March 15, 2010. As of March 2, 2009, $300 million of borrowings were outstanding. There is no guarantee that we will be able to replace the existing revolving credit facility with a replacement facility offering similar terms and credit amounts or at all. The replacement facility, if any, may impose less attractive terms and more severe restrictive covenants on us, and the credit amounts available under such replacement facility may be significantly lower. On October 24, 2007, we entered into the third amendment to the revolving credit facility with BNP Paribas, which increased the

maximum credit amount to $500 million from the initial amount of $300 million. Our obligations under the revolving credit facility are secured by mortgages on more than 80% of our oil and gas properties as well as a pledge of all of our ownership interests in our operating subsidiaries. The amount available for borrowing at any one time is limited to the borrowing base, currently at $410 million, which was initially set at $130 million and was increased on October 6, 2008 to $383.76 million pursuant to the fifth amendment to the revolving credit facility and further increased to $410 million on November 26, 2008 with the addition of two new member banks to the revolving credit facility. The borrowing base is subject to semi-annual re-determinations on April 1 and October 1 of each year. We expect that in connection with the next re-determination scheduled for April 1, 2009, the lenders under our revolving credit facility will lower our borrowing base to reflect the significantly lower commodity price outlook. As a result, the amount available for borrowing under our revolving credit facility is expected to decrease. Additionally, either we or the lenders may, once during each calendar year, elect to re-determine the borrowing base between scheduled re-determinations. We also have the right, once during each calendar year, to request the re-determination of the borrowing base upon the proposed acquisition of certain oil and gas properties where the purchase price is greater than 10% of the borrowing base. Any increase in the borrowing base requires the consent of all the lenders and any decrease in the borrowing base must be approved by the lenders holding 66 2/3% of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the revolving credit facility. If the required lenders do not agree on an increase or decrease, then the borrowing base will be the highest borrowing base acceptable to the lenders holding 66 2/3% of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the revolving credit facility so long as it does not increase the borrowing base then in effect. Outstanding borrowings in excess of the borrowing base must be prepaid, and, if mortgaged properties represent less than 80% of total value of oil and gas properties evaluated in the most recent reserve report, we must pledge other oil and natural gas properties as additional collateral.

We may elect that borrowings be comprised entirely of alternate base rate (ABR) loans or Eurodollar loans. Interest on the loans is determined as follows:

- with respect to ABR loans, the alternate base rate equals the higher of the prime rate or the Federal funds effective rate plus 0.50%, plus an applicable margin between 0% and 0.50%, or
- with respect to any Eurodollar loans, the London inter-bank rate, or LIBOR, plus an applicable margin ranging from and including 1.50% and 2.125% per annum, determined by the percentage of the borrowing base then in effect that is drawn.

Interest is generally payable quarterly for ABR loans and on the last day of the applicable interest period for any Eurodollar loans.

Our revolving credit facility also contains various covenants that limit our ability to:

- incur indebtedness;

- enter into certain leases;
- grant certain liens;
- enter into certain swaps;
- make certain loans, acquisitions, capital expenditures and investments;
- make distributions other than from available cash;
- merge, consolidate or allow any material change in the character of our business; or
- engage in certain asset dispositions, including a sale of all or substantially all of our assets.

Our revolving credit facility also contains covenants that, among other things, require us to maintain specified ratios or conditions as follows:

- consolidated net income plus interest expense, income taxes, depreciation, depletion, amortization, impairment and other similar charges excluding unrealized gains and losses under Statement of Financial Accounting Standards (SFAS) No. 133, minus all non-cash income added to consolidated net income, and giving pro forma effect to any acquisitions or capital expenditures, to interest expense of not less than 2.5 to 1.0;
- total debt to EBITDA of not more than 3.75 to 1.0 as amended on October 6, 2008, pursuant to the fifth amendment to the revolving credit facility; and
- consolidated current assets, including the unused amount of the total commitments, to consolidated current liabilities of not less than 1.0 to 1.0, excluding non-cash assets and liabilities under SFAS No. 133, which includes the current portion of oil, natural gas and interest rate swaps.

If an event of default exists under our revolving credit facility, the lenders will be able to accelerate the maturity of the credit agreement and exercise other rights and remedies. Each of the following would be an event of default:

- failure to pay any principal when due or any reimbursement amount, interest, fees or other amount within certain grace periods;
- a representation or warranty is proven to be incorrect when made;
- failure to perform or otherwise comply with the covenants or conditions contained in the credit agreement or other loan documents, subject, in certain instances, to certain grace periods;
- default by us on the payment of any other indebtedness in excess of $1.0 million, or any event occurs that permits or causes the acceleration of the indebtedness;
- bankruptcy or insolvency events involving us or any of our subsidiaries;
- the loan documents cease to be in full force and effect;
- our failing to create a valid lien, except in limited circumstances;
- a change of control, which will occur upon (i) the acquisition by any person or group of persons of beneficial ownership of more than 35% of the aggregate ordinary voting power of our equity securities, (ii) the first day on which a majority of the members of the board of directors of our general partner are not continuing directors (which is generally defined to mean members of our board of directors as of March 15, 2006 and persons who are nominated for election or elected to our general partner s board of directors with the

approval of a majority of the continuing directors who were members of such board of directors at the time of such nomination or election), (iii) the direct or indirect sale, transfer or other disposition in one or a series of related transactions of all or substantially all of the properties or assets (including equity interests of subsidiaries) of us and our subsidiaries to any person, (iv) the adoption of a plan related to our liquidation or dissolution or (v) Legacy Reserves GP, LLC s ceasing to be our sole general partner;

- the entry of, and failure to pay, one or more adverse judgments in excess of $1.0 million or one or more non-monetary judgments that could reasonably be expected to have a material adverse effect and for which enforcement proceedings are brought or that are not stayed pending appeal; and
- specified ERISA events relating to our employee benefit plans that could reasonably be expected to result in liabilities in excess of $1,000,000 in any year.

Off-Balance Sheet Arrangements

None.

Contractual Obligations

A summary of our contractual obligations as of December 31, 2008 is provided in the following table.

Contractual Cash Obligations	Obligations Due in Period 2009	2010-2011	2012-2013 (In thousands)	Thereafter	Total
Long-term debt(a)	$	$ 282,000	$	$	$ 282,000
Interest on long-term debt(b)	14,326	2,865			17,191
Derivative obligations(c)	1,691	9,070			10,761
Management compensation(d)	1,305	2,610	2,610		6,525
Asset retirement obligation(e)	25,889	1,245	1,962	51,328	80,424
Office lease	154	260	10		424
Total contractual cash obligations	$ 43,365	$ 298,050	$ 4,582	$ 51,328	$ 397,025

(a) Represents amounts outstanding under our revolving credit facility as of December 31, 2008.

(b) Based upon our interest rate of 5.08% under our revolving credit facility as of December 31, 2008.

(c) Derivative obligations represent net liabilities for derivatives that were valued as of December 31, 2008, the ultimate settlement of which are unknown because they are subject to continuing market risk. Please read Item 7A. Quantitative and Qualitative Disclosure about Market Risk for additional information regarding our derivative obligations.

(d) The related employment agreements do not contain termination provisions; therefore, the ultimate payment obligation is not known. For purposes of this table, management has not reflected payments subsequent to 2013.

(e) Asset retirement obligations of oil and natural gas assets, excluding salvage value and accretion, the ultimate settlement and timing of which cannot be precisely determined in advance.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations is based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is a reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. Estimates and assumptions are evaluated on a regular basis. We based our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of the financial statements. Changes in these estimates and assumptions could materially affect our financial position, results of operations or cash flows. Management considers an accounting estimate to be critical if:

- it requires assumptions to be made that were uncertain at the time the estimate was made, and
- changes in the estimate or different estimates that could have been selected could have a material impact on our consolidated results of operations or financial condition.

Please read Note 1 of the Notes to Consolidated Financial Statements for a detailed discussion of all significant accounting policies that we employ and related estimates made by management.

Nature of Critical Estimate Item: Oil and Natural Gas Reserves Our estimate of proved reserves is based on the quantities of oil and gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. LaRoche Petroleum Consultants, Ltd, prepares a reserve and economic evaluation of all our properties in accordance with

Securities and Exchange Commission, or SEC, guidelines on a lease, unit or well-by-well basis, depending on the availability of well-level production data. The accuracy of our reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgments of the individuals preparing the estimates. For example, we must estimate the amount and timing of future operating costs, severance taxes, development costs, and workover costs, all of which may in fact vary considerably from actual results. In addition, as prices and cost levels change from year to year, the economics of producing the reserves may change and therefore the estimate of proved reserves also may change. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves. Despite the inherent imprecision in these engineering estimates, our reserves are used throughout our financial statements. Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion rates are made concurrently with changes to reserve estimates.

Assumptions/Approach Used: Units-of-production method to deplete our oil and natural gas properties The quantity of reserves could significantly impact our depletion expense. Any reduction in proved reserves without a corresponding reduction in capitalized costs will increase the depletion rate.

Effect if Different Assumptions Used: Units-of-production method to deplete our oil and natural gas properties A 10% increase or decrease in reserves would have decreased or increased, respectively, our depletion expense for the year ended December 31, 2008 by approximately 10%.

Nature of Critical Estimate Item: Asset Retirement Obligations We have certain obligations to remove tangible equipment and restore land at the end of oil and gas production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells. We adopted Statement of Financial Accounting Standards (SFAS) No. 143, *Accounting for Asset Retirement Obligations*, effective January 1, 2003. SFAS No. 143 significantly changed the method of accruing for costs an entity is legally obligated to incur related to the retirement of fixed assets (asset retirement obligations or ARO). Primarily, SFAS No. 143 requires us to estimate asset retirement costs for all of our assets, adjust those costs for inflation to the forecast abandonment date, discount that amount using a credit-adjusted-risk-free rate back to the date we acquired the asset or obligation to retire the asset and record an ARO liability in that amount with a corresponding addition to our asset value. When new obligations are incurred, i.e. a new well is drilled or acquired, we add a layer to the ARO liability. We then accrete the liability layers quarterly using the applicable period-end effective credit-adjusted-risk-free rates for each layer. Should either the estimated life or the estimated abandonment costs of a property change materially upon our quarterly review, a new calculation is performed using the same methodology of taking the abandonment cost and inflating it forward to its abandonment date and then discounting it back to the present using our credit-adjusted-risk-free rate. The carrying value of the asset retirement obligation is adjusted to the newly calculated value, with a corresponding offsetting adjustment to the asset retirement cost. Thus, abandonment costs will almost always approximate the estimate. When well obligations are relieved by sale of the property or plugging and abandoning the well, the related liability and asset costs are removed from our balance sheet.

Assumptions/Approach Used: Estimating the future asset removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. Inherent in the estimate of the present value calculation of our AROs are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit-adjusted-risk-free rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments.

Effect if Different Assumptions Used: Since there are so many variables in estimating AROs, we attempt to limit the impact of management's judgment on certain of these variables by developing a standard cost estimate based on historical costs and industry quotes updated annually. Unless we expect a well's plugging to be significantly different than a normal abandonment, we use this estimate. The resulting estimate, after application of a discount factor and present value calculation, could differ from actual results, despite our efforts to make an accurate estimate. We engage independent engineering firms to evaluate our properties annually. We use the remaining estimated useful life from the year-end reserve report by our independent reserve engineers in estimating when

abandonment could be expected for each property. On an annual basis we evaluate our latest estimates against actual abandonment costs incurred. For the year ended December 31, 2008, actual abandonment costs materially exceeded our previous estimates. As a result, we revised future estimated costs to reflect these higher actual costs. We expect to see our calculations impacted significantly if interest rates continue to rise, as the credit-adjusted-risk-free rate is one of the variables used on a quarterly basis.

Nature of Critical Estimate Item: Derivative Instruments and Hedging Activities — We periodically use derivative financial instruments to achieve a more predictable cash flow from our oil, NGL and natural gas production and interest expense by reducing our exposure to price fluctuations and interest rate changes. Currently, these transactions are swaps and collars whereby we exchange our floating price for our oil, NGL and natural gas for a fixed price and floating interest rates for fixed rates with qualified and creditworthy counterparties. Our existing oil, NGL, natural gas and interest rate swaps and oil collar are with members of our lending group which enables us to avoid margin calls for out-of-the money mark-to-market positions.

We do not specifically designate derivative instruments as cash flow hedges, even though they reduce our exposure to changes in oil, NGL and natural gas prices and interest rate changes. Therefore, the mark-to-market of these instruments is recorded in current earnings. We use market value estimates prepared by a third party firm, which specializes in valuing derivatives, and validate these estimates by comparison to counterparty estimates as the basis for these end-of-period mark-to-market adjustments. When we record a mark-to-market adjustment resulting in a loss in a current period, these unrealized losses represent a current period mark-to-market adjustment for commodity derivatives which will be settled in future period. As shown in the tables above, we have hedged a significant portion of our future production through 2013. Taking into account the mark-to-market liabilities and assets recorded as of December 31, 2008, the future cash obligations table presented above shows the amounts which we would expect to pay the counterparties over the time periods shown. As oil and gas prices rise and fall, our future cash obligations related to these derivatives will rise and fall.

Consolidation of Variable Interest Entity

FASB Interpretation No. 46 (revised December 2003) (FIN 46R) *Consolidation of Variable Interest Entities*, addresses how a business enterprise should evaluate whether it has a controlling financial interest in an entity through means other than voting rights and, accordingly, should consolidate the entity. Through March 15, 2006 MBN Properties LP was a variable interest entity since MBN Properties LP required additional subordinated financial support to commence its activities. Legacy consolidated MBN Properties LP as a variable interest entity under FASB FIN 46R because it was the primary beneficiary of MBN Properties LP under the expected losses test of paragraph 14 of FIN 46R. While MBN Management, LLC is a variable interest entity, through March 15, 2006 it was accounted for by Legacy utilizing the equity method since no entity was the primary beneficiary. As we have acquired all of MBN Properties LPs properties in the formation transactions on March 15, 2006, after that date there are no remaining non-controlling interests related to MBN Properties LP. On April 16, 2007, as a part of the Binger Acquisition, Legacy acquired a 50% non-controlling interest in BOL. While BOL is a variable interest entity, it was accounted for by Legacy utilizing the equity method since no entity was the primary beneficiary.

Recently Issued Accounting Pronouncements

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements.* SFAS No. 157 defines fair value as used in numerous accounting pronouncements, establishes a framework for measuring fair value in GAAP and expands disclosure related to the use of fair value measures in financial statements. We adopted the Statement effective January 1, 2008 and the adoption did not have a significant effect on our consolidated results of operations, financial position or cash flows. See Note 8 of the Notes to Consolidated Financial Statements for other disclosures required by SFAS No. 157.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* (SFAS 141(R)), which replaces FASB SFAS No. 141. SFAS 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non-controlling interest in the acquiree and the goodwill acquired. The Statement also establishes disclosure requirements that will enable users to evaluate the nature and financial effects of the business combination.

SFAS 141(R) is effective for acquisitions that occur in an entitys fiscal year that begins after December 15, 2008, which will be Legacys fiscal year 2009. The impact, if any, will depend on the nature and size of business combinations we consummate after the effective date.

In December 2007, the FASB issued SFAS No. 160, *Non-controlling Interests in Consolidated Financial Statements an amendment of ARB No. 51* (SFAS 160). SFAS 160 requires that accounting and reporting for minority interests will be re-characterized as non-controlling interests and classified as a component of equity. SFAS 160 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners. SFAS 160 applies to all entities that prepare consolidated financial statements, except not-for-profit organizations, but will affect only those entities that have an outstanding non-controlling interest in one or more subsidiaries or that deconsolidate a subsidiary. This statement is effective as of the beginning of an entitys first fiscal year beginning after December 15, 2008, which will be Legacys fiscal year 2009. Based upon the December 31, 2008 balance sheet, the statement would have no impact.

In March, 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities* (SFAS 161). SFAS 161 amends and expands the disclosure requirements of FASB SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* SFAS 161 requires disclosures related to objectives and strategies for using derivatives; the fair-value amounts of, and gains and losses on, derivative instruments; and credit-risk-related contingent features in derivative agreements. This statement is effective as of the beginning of an entitys fiscal year beginning after December 15, 2008, which will be our fiscal year 2009. The effect on our disclosures for derivative instruments as a result of the adoption of SFAS 161 in 2009 will depend on our derivative instruments and hedging activities at that time.

During May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles* (SFAS 162). SFAS 162 identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements presented in conformity with GAAP. SFAS 162 is effective 60 days following the SECs approval of the Public Company Accounting Oversight Board amendments to

AU Section 411, *The Meaning of* Present Fairly in Conformity With Generally Accepted Accounting Principles. We do not expect that the adoption of SFAS 162 will have a significant impact on our financial statements.

In June 2008, the FASB issued FASB Staff Position No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* (FSP 03-6-1), which addresses whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the net income allocation in computing basic net income per share under the two class method prescribed under SFAS 128, *Earnings per Share*. FSP 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and, to the extent applicable, must be applied retrospectively by adjusting all prior-period net income per share data to conform to the provisions of the standard. The adoption of FSP 03-6-1 is not expected to have a material effect on our net income per common unit calculations.

In December 2008, the SEC released Final Rule, *Modernization of Oil and Gas Reporting*. The new disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes. The new requirements also will allow companies to disclose their probable and possible reserves to investors. In addition, the new disclosure requirements require companies to: (a) report the independence and qualifications of its reserves preparer or auditor; (b) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserves audit; and (c) report oil and natural gas reserves using an average price based upon the prior 12-month period rather than year-end prices. The use of average prices will affect future impairment and depletion calculations. The new disclosure requirements are effective for annual reports on Forms 10-K for fiscal years ending on or after December 31, 2009. Legacy is currently assessing the impact that adoption of this rule will have on its financial statements, which will vary depending on changes in commodity prices.

ITEM 7A. *QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK*

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our oil and natural gas production. Realized pricing is primarily driven by the spot market prices applicable to our natural gas production and the prevailing price for crude oil. Pricing for oil and natural gas has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control, such as the strength of the global economy and the supply of oil outside of the United States.

We periodically enter into and anticipate entering into derivative arrangements with respect to a portion of our projected oil and natural gas production through various transactions that offset changes in the future prices received. These transactions may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. Additionally, we may enter into put options, whereby we pay a premium in exchange for the option to receive a fixed price at a future date. At the settlement date we receive the excess, if any, of the fixed floor over the floating rate. These derivative activities are intended to support oil and natural gas prices at targeted levels and to manage our exposure to oil and natural gas price fluctuations. We do not hold or issue derivative instruments for speculative trading purposes.

As of December 31, 2008, the fair market value of Legacy's commodity derivative positions was a net asset of $134.9 million. As of December 31, 2007, the fair market value of Legacy's commodity derivative positions was a net liability of $82.3 million. Due to our asset position on commodity derivatives we routinely monitor the credit default risk of our counterparties via risk monitoring services. For more discussion about our derivative transactions and to see a table listing the oil, NGL and natural gas swaps for 2009 through December 31, 2013, please read Investing Activities.

If oil prices decline by $1.00 per Bbl, then the standardized measure of our combined proved reserves as of December 31, 2008 would decline from $235.0 million to $226.5 million, or 3.6%. If natural gas prices decline by $0.10 per Mcf, then the standardized measure of our combined proved reserves as of December 31, 2008 would decline from $235.0 million to $232.5 million, or 1.1%. However, larger decreases in oil and natural gas prices may not have the same impact to our standardized measure.

Interest Rate Risks

At December 31, 2008, Legacy had debt outstanding of $282 million, which incurred interest at floating rates in accordance with its revolving credit facility. The average annual interest rate incurred by Legacy for year ended December 31, 2008 was 5.23%. A 1% increase in LIBOR on Legacys outstanding debt as of December 31, 2008 would result in an estimated $0.18 million increase in annual interest expense, exclusive of interest rate swap mark-to-market expense, as Legacy has entered into interest rate swaps to hedge the volatility of interest rates through December of 2013 on $264 million of floating rate debt to a weighted average fixed rate of 3.235%.

ITEM 8. ***FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA***

Our Consolidated Financial Statements and supplementary financial data are included in this annual report on Form 10-K beginning on page F-1.

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

None.

ITEM 9A. ***CONTROLS AND PROCEDURES***

We maintain disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended, or the Exchange Act,) that are designed to ensure that information required to be disclosed in Exchange Act reports is recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the SEC and that such information is accumulated and communicated to our management, including our general partners Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. Any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives.

Our management, with the participation of our general partners Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of December 31, 2008. Based upon that evaluation and subject to the foregoing, our general partners Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures provide reasonable assurance that such controls and procedures were effective to accomplish their objectives.

Our general partners Chief Executive Officer and Chief Financial Officer do not expect that our disclosure controls or our internal controls will prevent all error and all fraud. The design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be considered relative to their cost. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that we have detected all of our control issues and all instances of fraud, if any. The design of any system of controls also is based partly on certain assumptions about the likelihood of future events and there can be no assurance that any design will succeed in achieving our stated goals under all potential future conditions.

There have been no changes in our internal control over financial reporting that occurred during our fiscal quarter ended December 31, 2008, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting

Legacy's management is responsible for establishing and maintaining adequate control over financial reporting. Our internal control over financial reporting is a process designed by, or under the supervision of, our general partner's Chief Executive Officer and Chief Financial Officer, and effected by the board of directors of our general partner, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Our internal control over financial reporting includes those policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of management and the board of directors of our general partner; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisitions, use or disposition of our assets that could have a material effect on our financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. 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 and procedures may deteriorate.

As of December 31, 2008, management assessed the effectiveness of Legacy's internal control over financial reporting based on the criteria for effective internal control over financial reporting established in "Internal Control — Integrated Framework," issued by the Committee of Sponsoring Organizations of the Treadway Commission. This assessment included design, effectiveness and operating effectiveness of internal controls over financial reporting as well as the safeguarding of assets. Based on that assessment, management determined that Legacy maintained effective internal control over financial reporting as of December 31, 2008, based on those criteria.

BDO Seidman, LLP, the independent registered public accounting firm who also audited our Consolidated Financial Statements included in this Annual Report on Form 10-K, has issued an attestation report on our internal control over financial reporting as of December 31, 2008, which is set forth below under "Attestation Report."

Attestation Report

Report of Independent Registered Public Accounting Firm on Internal Control over Financial Reporting

Board of Directors and Unitholders
Legacy Reserves LP
Midland, Texas

We have audited Legacy Reserves LP's internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Legacy Reserves LP's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying "Item 9A, Management's Annual Report on Internal Control Over Financial Reporting". Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of 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.

In our opinion, Legacy Reserves LP maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Legacy Reserves LP as of December 31, 2008 and 2007, and the related consolidated statements of operations, unitholders' equity, and cash flows for each of the three years in the period ended December 31, 2008 and our report dated March 5, 2009 expressed an unqualified opinion thereon.

/s/ BDO Seidman, LLP
Houston, Texas
March 5, 2009

ITEM 9B. ***OTHER INFORMATION***

None.

PART III

ITEM 10. ***DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE***

We intend to include the information required by this Item 10 in Legacy's definitive proxy statement for its 2009 annual meeting of unitholders under the headings "Election of Directors," "Corporate Governance" and "Section 16(a) Beneficial Ownership Reporting Compliance," which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2008.

ITEM 11. ***EXECUTIVE COMPENSATION***

We intend to include information with respect to executive compensation in Legacy's definitive proxy statement for its 2009 annual meeting of unitholders under the heading "Executive Compensation," which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2008.

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

We intend to include information regarding Legacy’s securities authorized for issuance under equity compensation plans and ownership of Legacy’s outstanding securities in Legacy’s definitive proxy statement for its 2009 annual meeting of unitholders under the headings “Equity Compensation Plan Information” and “Security Ownership of Certain Beneficial Owners and Management,” respectively, which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2008.

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

We intend to include the information regarding related party transactions in Legacy’s definitive proxy statement for its 2009 annual meeting of unitholders under the headings “Corporate Governance” and “Certain Relationships and Related Transactions,” which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2008.

ITEM 14. *PRINCIPAL ACCOUNTING FEES AND SERVICES*

We intend to include information regarding principal accountant fees and services in Legacy’s definitive proxy statement for its 2009 annual meeting of unitholders under the heading “Independent Registered Public Accounting Firm,” which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2008.

PART IV

ITEM 15. *EXHIBITS, FINANCIAL STATEMENT SCHEDULES*

(a)(1) and (2) Financial Statements

The consolidated financial statements of Legacy Reserves LP are listed on the Index to Financial Statements to this annual report on Form 10-K beginning on page F-1.

(a)(3) Exhibits

The following documents are filed as a part of this annual report on Form 10-K or incorporated by reference:

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Legacy Reserves LP (Incorporated by reference to Legacy Reserves LP’s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 3.1)
3.2	Amended and Restated Limited Partnership Agreement of Legacy Reserves LP (Incorporated by reference to Legacy Reserves LP’s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, included as Appendix A to the Prospectus and including specimen unit certificate for the units)
3.3	Amendment No. 1, dated December 27, 2007, to the Amended and Restated Agreement of Limited Partnership of Legacy Reserves LP (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K filed January 2, 2008, Exhibit 3.1)
3.4	Certificate of Formation of Legacy Reserves GP, LLC (Incorporated by reference to Legacy Reserves LP’s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 3.3)

3.5 Amended and Restated Limited Liability Company Agreement of Legacy Reserves GP, LLC (Incorporated by reference to Legacy Reserves LPs Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 3.4)

4.1 Registration Rights Agreement dated June 29, 2006, between Henry Holdings LP and Legacy Reserves LP and Legacy Reserves GP, LLC (the Henry Registration Rights Agreement) (Incorporated by reference to Legacy Reserves LPs Registration Statement on Form S-1 (File No. 333-134056) filed September 5. 2006, Exhibit 4.2)

4.2 Registration Rights Agreement dated March 15, 2006, by and among Legacy Reserves LP, Legacy Reserves GP, LLC and the other parties there to (the Founders Registration Rights Agreement) (Incorporated by reference to Legacy Reserves LPs Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006, Exhibit 4.3)

4.3 Registration Rights Agreement dated April 16, 2007, by and among Nielson & Associates, Inc., Legacy Reserves GP, LLC and Legacy Reserves LP (Incorporated by reference to Legacy Reserves LPs quarterly report on Form 10-Q filed May 14, 2007, Exhibit 4.4)

10.1 Credit Agreement dated as of March 15, 2006, among Legacy Reserves LP, the lenders from time to time party thereto, and BNP Paribas, as administrative agent (Incorporated by reference to Legacy Reserves LPs Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.1)

10.2 First Amendment to Credit Agreement effective as of July 7, 2006, among Legacy Reserves LP, the lenders signatory thereto, and BNP Paribas, as administrative agent (Incorporated by reference to Legacy Reserves LPs Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006, Exhibit 10.14)

Exhibit Number	Description
10.3	Second Amendment to Credit Agreement dated May 3, 2007, among Legacy Reserves LP, the lenders signatory thereto, and BNP Paribas, as administrative agent (Incorporated by reference to Legacy Reserves LPs current report on Form 8-K filed May 8, 2007, Exhibit 10.1)
10.4	Third Amendment to Credit Agreement dated October 24, 2007, among Legacy Reserves LP, the lenders signatory thereto, and BNP Paribas, as administrative agent (Incorporated by reference to Legacy Reserves LPs current report on Form 8-K filed October 29, 2007, Exhibit 10.1)
10.5	Fourth Amendment to Credit Agreement dated April 24, 2008, among Legacy Reserves LP, the lenders signatory thereto, and BNP Paribas, as administrative agent (Incorporated by reference to Legacy Reserves LPs current report on Form 8-K filed April 25, 2008, Exhibit 10.1)
10.6	Fifth Amendment to Credit Agreement dated October 6, 2008, among Legacy Reserves LP, the lenders signatory thereto, and BNP Paribas, as administrative agent (Incorporated by reference to Legacy Reserves LPs current report on Form 8-K filed October 7, 2008, Exhibit 10.1)
10.7	Contribution, Conveyance and Assumption Agreement dated as of March 15, 2006, by and among Legacy Reserves LP, Legacy Reserves GP, LLC and the other parties thereto (Incorporated by reference to Legacy Reserves LPs Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.2)
10.8	Omnibus Agreement dated as of March 15, 2006, among Legacy Reserves LP, Legacy Reserves GP, LLC and the other parties thereto (Incorporated by reference to Legacy Reserves LPs Registration

	Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.3)
10.9	Legacy Reserves, LP Long-Term Incentive Plan (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.5)
10.10	First Amendment of Legacy Reserves LP to Long Term Incentive Plan dated June 16, 2006 (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 333-134056) filed October 5, 2006, Exhibit 10.17)
10.11	Amended and Restated Legacy Reserves LP Long-Term Incentive Plan effective as of August 17, 2007 (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K filed August 23, 2007, Exhibit 10.1)
10.12	Form of Legacy Reserves LP Long-Term Incentive Plan Restricted Unit Grant Agreement (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.6)
10.13	Form of Legacy Reserves LP Long-Term Incentive Plan Unit Option Grant Agreement (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006, Exhibit 10.7)
10.14	Form of Legacy Reserves LP Long-Term Incentive Plan Unit Grant Agreement (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006, Exhibit 10.8)
10.15	Form of Legacy Reserves LP Long-Term Incentive Plan Grant of Phantom Units (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K filed February 4, 2008, Exhibit 10.1)
10.16	Employment Agreement dated as of March 15, 2006, between Cary D. Brown and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 333- 134056) filed May 12, 2006, Exhibit 10.9)
10.17	Section 409A Compliance Amendment to Employment Agreement dated December 30, 3008, between Cary D. Brown and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K filed December 31, 2008, Exhibit 10.1)

Exhibit Number	Description
10.18	Employment Agreement dated as of March 15, 2006, between Steven H. Pruett and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.10)
10.19	Section 409A Compliance Amendment to Employment Agreement dated December 30, 3008, between Steven H. Pruett and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K filed December 31, 2008, Exhibit 10.2)
10.20	Employment Agreement dated as of March 15, 2006, between Kyle A. McGraw and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.11)
10.21	Section 409A Compliance Amendment to Employment Agreement dated December 30, 3008, between Kyle A. McGraw and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K filed December 31, 2008, Exhibit 10.3)
10.22	Employment Agreement dated as of March 15, 2006, between Paul T. Horne and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP's Registration Statement on Form S-1

(File No. 333- 134056) filed May 12, 2006, Exhibit 10.12)

10.23 Section 409A Compliance Amendment to Employment Agreement dated December 30, 3008, between Paul T. Horne and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LPs current report on Form 8-K filed December 31, 2008, Exhibit 10.4)

10.24 Employment Agreement dated as of March 15, 2006, between William M. Morris and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LPs Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.13)

10.25 Section 409A Compliance Amendment to Employment Agreement dated December 30, 3008, between William M. Morris and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LPs current report on Form 8-K filed December 31, 2008, Exhibit 10.5)

10.26 Binger Purchase, Sale and Contribution Agreement dated March 20, 2007, by and between Nielson & Associates, Inc. and Legacy Reserves Operating LP (Incorporated by reference to Legacy Reserves LPs quarterly report on Form 10-Q filed May 14, 2007, Exhibit 10.1)

10.27 Purchase and Sale Agreement dated March 29, 2007, by and between Ameristate Exploration, LLC and Legacy Reserves Operating LP (Incorporated by reference to Legacy Reserves LPs current report on Form 8-K filed May 4, 2007, Exhibit 10.1)

10.28 Purchase and Sale Agreement dated April 10, 2007, by and between Terry S. Fields and Legacy Reserves Operating LP (Incorporated by reference to Legacy Reserves LPs quarterly report on Form 10-Q filed August 13, 2007, Exhibit 10.1)

10.29 Purchase and Sale Agreement dated May 3, 2007, by and between Raven Resources, LLC and Shenandoah Petroleum Corporation and Legacy Reserves Operating LP (Incorporated by reference to Legacy Reserves LPs quarterly report on Form 10-Q filed August 13, 2007, Exhibit 10.2)

10.30 Purchase and Sale Agreement dated July 11, 2007, by and between Raven Resources, LLC and Legacy Reserves Operating LP (Incorporated by reference to Legacy Reserves LPs quarterly report on Form 10-Q filed November 9, 2007, Exhibit 10.1)

10.31 Purchase and Sale Agreement dated August 28, 2007, between Summit Petroleum Management Corporation and Legacy Reserves Operating LP (Incorporated by reference to Legacy Reserves LPs quarterly report on Form 10-Q filed November 9, 2007, Exhibit 10.3)

10.32 Purchase and Sale Agreement dated August 30, 2007, by and between The Operating Company and Legacy Reserves Operating LP (Incorporated by reference to Legacy Reserves LPs quarterly report on Form 10-Q filed November 9, 2007, Exhibit 10.4)

Exhibit Number	Description
10.33	Unit Purchase Agreement dated as of November 7, 2007, by and among Legacy Reserves LP, Legacy Reserves GP, LLC and the Purchasers named therein (Incorporated by reference to Legacy Reserves LPs current report on Form 8-K filed November 9, 2007, Exhibit 10.1)
10.34	Purchase and Sale Agreement dated March 13, 2008, by and between Crown Oil Partners III, LP, BC Operating, Inc. and Legacy Reserves Operating LP (Incorporated by reference to Legacy Reserves LPs current report on Form 8-K filed May 5, 2008, Exhibit 10.1)
10.35	Purchase and Sale Agreement dated September 5, 2008, by and among Cano Petroleum Inc., Pantwist, LLC and Legacy Reserves Operating LP (Incorporated by reference to Legacy Reserves LPs current report on Form 8-K filed October 7, 2008, Exhibit 10.2)

10.36	Participation Agreement dated as of September 24, 2008, between Black Oak Resources, LLC and Legacy Reserves Operating LP (Incorporated by reference to Legacy Reserves LPs quarterly report on Form 10-Q filed November 7, 2008, Exhibit 10.1)
21.1	List of subsidiaries of Legacy Reserves LP (Incorporated by reference to Legacy Reserves LPs Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 21.1)
23.1*	Consent of BDO Seidman LLP
23.2*	Consent of LaRoche Petroleum Consultants, Ltd.
31.1*	Rule 13a-14(a) Certification of CEO (under Section 302 of the Sarbanes-Oxley Act of 2002)
31.2*	Rule 13a-14(a) Certification of CFO (under Section 302 of the Sarbanes-Oxley Act of 2002)
32.1*	Section 1350 Certifications (under Section 906 of the Sarbanes-Oxley Act of 2002)

* Filed herewith
Management contract or compensatory plan or arrangement

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this annual report on Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized, on the 6th day of March, 2009.

LEGACY RESERVES LP

By: LEGACY RESERVES GP, LLC,
its general partner

By: /S/ STEVEN H. PRUETT
Name: Steven H. Pruett
Title: President, Chief Financial Officer and Secretary (Principal Financial Officer)

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below hereby constitutes and appoints Cary D Brown and Steven H. Pruett, or either of them, each with power to act without the other, his true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities, to sign any or all subsequent amendments and supplements to this Annual Report on Form 10-K, and to file the same, or cause to be filed the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto each said attorney-in-fact and agent full power to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby qualifying and confirming all that said attorney-in-fact and agent or his substitute or substitutes may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this annual report on Form 10-K has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/S/ CARY D. BROWN Cary D. Brown	Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	March 6, 2009
/S/ STEVEN H. PRUETT Steven H. Pruett	President, Chief Financial Officer and Secretary (Principal Financial Officer)	March 6, 2009
/S/ WILLIAM M. MORRIS William M. Morris	Vice President, Chief Accounting Officer and Controller (Principal Accounting Officer)	March 6, 2009
/S/ KYLE A. MCGRAW Kyle A. McGraw	Executive Vice President and Director	March 6, 2009
/S/ DALE A. BROWN Dale A. Brown	Director	March 6, 2009
/S/ WILLIAM R. GRANBERRY William R. Granberry	Director	March 6, 2009
/S/ G. LARRY LAWRENCE G. Larry Lawrence	Director	March 6, 2009
/S/ WILLIAM D. SULLIVAN William D. Sullivan	Director	March 6, 2009
/S/ KYLE D. VANN Kyle D. Vann	Director	March 6, 2009

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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Report of Independent Registered Public Accounting Firm

Legacy Reserves LP
Midland, Texas

We have audited the accompanying consolidated balance sheets of Legacy Reserves LP as of December 31, 2008 and 2007 and the related consolidated statements of operations, unitholders equity, and cash flows for each of the years in the three year period ended December 31, 2008. These financial statements are the responsibility of the Partnerships management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Legacy Reserves LP at December 31, 2008 and 2007 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Legacy Reserves LPs internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 5, 2009, expressed an unqualified opinion thereon.

/s/ BDO SEIDMAN, LLP

Houston, Texas
March 5, 2009

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LEGACY RESERVES LP

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2008 AND 2007

	2008	2007
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2,500	$ 9,604
Accounts receivable, net:		
Oil and natural gas	12,198	19,025
Joint interest owners	7,265	4,253
Other (Note 5)	60	26
Fair value of derivatives (Notes 8 and 9)	54,820	310

Prepaid expenses and other current assets	4,094	340
Total current assets	80,937	33,558
Oil and natural gas properties, at cost:		
Proved oil and natural gas properties, at cost, using the successful efforts method of accounting (Note 14)	821,786	512,396
Unproved properties	78	78
Accumulated depletion, depreciation and amortization	(208,832)	(72,294)
	613,032	440,180
Other property and equipment, net of accumulated depreciation and amortization of $765 and $251, respectively	1,851	775
Operating rights, net of amortization of $1,429 and $865, respectively (Note 1(k))	5,588	6,151
Fair value of derivatives (Notes 8 and 9)	80,085	
Other assets, net of amortization of $1,139 and $391, respectively	1,558	822
Investment in equity method investee (Note 4)	21	92
Total assets	$ 783,072	$ 481,578
LIABILITIES AND UNITHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 5,950	$ 2,320
Accrued oil and natural gas liabilities	17,200	10,102
Fair value of derivatives (Notes 8 and 9)	1,691	26,761
Asset retirement obligation (Note 11)	25,889	845
Other (Note 13)	6,276	3,429
Total current liabilities	57,006	43,457
Long-term debt (Note 3)	282,000	110,000
Asset retirement obligation (Note 11)	54,535	15,075
Fair value of derivatives (Notes 8 and 9)	8,768	57,316
Other long-term liabilities	130	
Total liabilities	402,439	225,848
Commitments and contingencies (Note 6)		
Unitholders equity:		
Limited partners equity 31,049,299 and 29,670,887 units issued and outstanding at December 31, 2008 and 2007, respectively	380,509	255,663
General partners equity (approximately 0.1%)	124	67
Total unitholders equity	380,633	255,730
Total liabilities and unitholders equity	$ 783,072	$ 481,578

See accompanying notes to consolidated financial statements.

LEGACY RESERVES LP

CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2008, 2007 AND 2006

	2008	2007	2006
	(In thousands, except per unit data)		
Revenues:			
Oil sales	$ 157,973	$ 83,301	$ 45,351

Natural gas liquids sales (NGL)	15,862	7,502	—
Natural gas sales	41,589	21,433	14,446
Total revenues	215,424	112,236	59,797
Expenses:			
Oil and natural gas production	52,004	27,129	15,938
Production and other taxes	12,712	7,889	3,746
General and administrative	11,396	8,392	3,691
Depletion, depreciation, amortization and accretion	63,324	28,415	18,395
Impairment of long-lived assets	76,942	3,204	16,113
Loss on disposal of assets	602	527	42
Total expenses	216,980	75,556	57,925
Operating income (loss)	(1,556)	36,680	1,872
Other income (expense):			
Interest income	93	321	130
Interest expense (Notes 3, 8 and 9)	(21,153)	(7,118)	(6,645)
Equity in income (loss) of partnerships (Note 4)	108	77	(318)
Realized and unrealized gain (loss) on oil, NGL and natural gas swaps and oil collar (Notes 8 and 9)	176,943	(85,156)	9,289
Other	116	(129)	29
Income (loss) before income taxes	154,551	(55,325)	4,357
Income taxes	(48)	(337)	—
Income (loss) from continuing operations	154,503	(55,662)	4,357
Gain on sale of discontinued operation (Note 4)	3,704	—	—
Net income (loss)	$ 158,207	$ (55,662)	$ 4,357
Income (loss) from continuing operations per unit — basic and diluted (Note 12)	$ 5.05	$ (2.13)	$ 0.26
Gain on discontinued operation per unit — basic and diluted	$ 0.12	$ —	$ —
Net income (loss) per unit — basic and diluted (Note 12)	$ 5.17	$ (2.13)	$ 0.26
Weighted average number of units used in computing net income per unit — basic	30,596	26,155	16,567
diluted	30,616	26,155	16,569

See accompanying notes to consolidated financial statements.

LEGACY RESERVES LP

CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2008, 2007 AND 2006

	Number of Limited Partner Units	Limited Partner	General Partner	Total Unitholders Equity
		(In thousands)		
Balance, December 31, 2005	9,489	$ 9,899	$ 10	$ 9,909
Capital contributions	—	19	—	19
Net distributions to owners	—	(2,295)	(2)	(2,297)

Deemed dividend to Moriah Group owners	—	(3,874)	(4)	(3,878)
Net proceeds from private equity offering	5,000	76,707	77	76,784
Redemption of Founding Investors’ units	(4,400)	(69,868)	(70)	(69,938)
Units issued to MBN Properties LP in exchange for the non-controlling interests’ share of oil and natural gas properties	1,867	31,712	32	31,744
Units issued to the Brothers Group in exchange for oil and natural gas properties and other assets	6,200	105,301	105	105,406
Units issued to H2K Holdings Ltd in exchange for oil and natural gas properties	84	1,418	1	1,419
Dividend — reimbursement of offering costs paid by MBN Management LLC	—	(1,199)	(1)	(1,200)
Units issued to Henry Holding LP in exchange for oil and natural gas properties	146	2,489	—	2,489
Units issued to Legacy Board of Directors for services	9	149	—	149
Compensation expense on unit options granted to employees	—	115	—	115
Compensation expense on restricted unit awards issued to employees	—	270	—	270
Distributions to unitholders, $0.8974 per unit	—	(16,542)	(16)	(16,558)
Net income	—	4,353	4	4,357
Balance, December 31, 2006	18,395	138,654	136	138,790
Net proceeds from initial public equity offering	6,900	121,554	—	121,554
Net proceeds from private placement equity offering	3,643	73,073	—	73,073
Units issued to Legacy Board of Directors for services	7	148	—	148
Compensation expense on restricted unit awards issued to employees	—	341	—	341
Vesting of Restricted Units	20	—	—	—
Units issued to Greg McCabe in exchange for oil and natural gas properties	95	2,271	—	2,271
Units issued to Nielson & Associates, Inc. in exchange for oil and natural gas properties	611	15,752	—	15,752
Reclass prior period compensation cost on unit options granted to employees to adjust for conversion to liability method as described in SFAS No.123(R)	—	(115)	—	(115)
Distributions to unitholders, $1.67 per unit	—	(40,388)	(34)	(40,422)
Net loss	—	(55,627)	(35)	(55,662)
Balance, December 31, 2007	29,671	255,663	67	255,730
Costs associated with private placement equity offering in the year ended December 31, 2007	—	(5)	—	(5)
Units issued to Legacy Board of Directors for services	13	263	—	263
Compensation expense on restricted unit awards issued to employees	—	342	—	342
Vesting of restricted units	20	—	—	—
Units issued in COP III acquisition	1,345	27,000	—	27,000
Distributions to unitholders, $1.98 per unit	—	(60,868)	(36)	(60,904)
Net income	—	158,114	93	158,207
Balance, December 31, 2008	31,049	$ 380,509	$ 124	$ 380,633

See accompanying notes to consolidated financial statements.

LEGACY RESERVES LP

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2008, 2007 AND 2006

	2008	2007	2006
		(In thousands)	
Cash flows from operating activities:			
Net income (loss)	$ 158,207	$ (55,662)	$ 4,35
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation, amortization and accretion	63,324	28,415	18,39
Amortization of debt issuance costs	748	224	36
Impairment of long-lived assets	76,942	3,204	16,11
(Gain) loss on derivatives	(167,980)	86,652	(9,28
Equity in (income) loss of partnership	(108)	(77)	31
Amortization of unit-based compensation	961	166	53
(Gain) loss on disposal of assets	(3,102)	527	4
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable, oil and natural gas	6,827	(11,425)	(5,79
(Increase) decrease in accounts receivable, joint interest owners	(3,012)	92	(4,48
(Increase) decrease in accounts receivable, other	(34)	(5)	(45
Increase in other current assets	(4,094)	(250)	(56
Increase (decrease) in accounts payable	3,630	(611)	2,69
Increase in accrued oil and natural gas liabilities	7,098	4,221	4,22
Increase in due to affiliates	—	—	1,05
Increase in other liabilities	1,578	1,676	2,07
Total adjustments	(17,222)	112,809	25,23
Net cash provided by operating activities	140,985	57,147	29,59
Cash flows from investing activities:			
Investment in oil and natural gas properties	(216,390)	(196,031)	(55,90
Investment in other equipment	(1,590)	(671)	(24
Investment in operating rights	—	—	(7,01
Collection of notes receivable	—	—	92
Net cash settlements on oil and natural gas swaps	(40,233)	211	(26
Investment in equity method investee	178	(14)	
Net cash used in investing activities	(258,035)	(196,505)	(62,50
Cash flows from financing activities:			
Proceeds from long-term debt	255,000	183,000	121,80
Payments of long-term debt	(83,000)	(188,800)	(73,19
Payments of debt issuance costs	(1,144)	(505)	(29
Proceeds (costs) from issuance of units, net	(6)	194,627	76,78
Redemption of Founding Investors’ units	—	—	(69,93
Dividend — reimbursement of offering costs paid by MBN Management LLC	—	—	(1,20
Capital contributed by owner	—	—	1
Cash not acquired in Legacy formation transactions	—	—	(3,10
Distributions to unitholders	(60,904)	(40,422)	(18,85
Net cash provided by financing activities	109,946	147,900	32,02
Net increase (decrease) in cash and cash equivalents	(7,104)	8,542	(89
Cash and cash equivalents, beginning of period	9,604	1,062	1,95
Cash and cash equivalents, end of period	$ 2,500	$ 9,604	$ 1,06

LEGACY RESERVES LP

CONSOLIDATED STATEMENTS OF CASH FLOWS — (Continued)

	2008	2007	2006
		(In thousands)	
Non-Cash Investing and Financing Activities:			
Asset retirement obligation costs and liabilities	$ 38,829	$ 6,296	$ 2,273
Asset retirement obligations associated with property acquisitions	$ 25,023	$ 3,034	$ 1,889
Non-controlling interests' share of net financing costs of MBN Properties LP capitalized to oil and natural gas properties	$ —	$ —	$ 164
Units issued to MBN Properties LP in exchange for the non-controlling interests' share of oil and natural gas properties	$ —	$ —	$ 31,744
Units issued to Brothers Group in exchange for:			
Oil and natural gas properties	$ —	$ —	$ 105,299
Other property and equipment	$ —	$ —	$ 107
Units issued to H2K Holdings Ltd. in exchange for oil and natural gas properties	$ —	$ —	$ 1,419
Oil and natural gas hedge liabilities assumed from the Brothers Group and H2K Holdings Ltd.	$ —	$ —	$ 3,147
Units issued in exchange for oil and natural gas properties	$ 27,000	$ 18,023	$ 2,489
Non-cash exchange of oil and gas properties:			
Properties received in exchange	$ 6,523	$ —	$ —
Properties delivered in exchange	$ (3,122)	$ —	$ —
Deemed dividend to Moriah Group owners for accounts not acquired in Legacy formation transaction:			
Accounts receivable, oil and natural gas	$ —	$ —	$ 4,248
Accounts receivable, joint interest owners	$ —	$ —	$ 250
Accounts receivable, other	$ —	$ —	$ 540
Other assets	$ —	$ —	$ 891
Accounts payable	$ —	$ —	$ (214)
Accrued oil and natural gas liabilities	$ —	$ —	$ (1,521)
Due to affiliates	$ —	$ —	$ (1,254)
Other liabilities	$ —	$ —	$ (2,166)

See accompanying notes to consolidated financial statements.

LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

(a) Organization, Basis of Presentation and Description of Business

On March 15, 2006, Legacy Reserves LP ("LRLP," "Legacy" or the "Partnership"), as the successor entity to the Moriah Group (defined below), completed a private equity offering in which it (1) issued 5,000,000 limited partnership units at a gross price of $17.00 per unit, netting $76.8 million after initial purchaser's discount, placement agent's fee and expenses, (2) acquired certain oil and natural gas properties (Note 4) and (3) redeemed 4.4 million units for $69.9 million from certain of its Founding Investors. The Moriah Group has been treated as the acquiring entity in this transaction, hereinafter referred to as the "Legacy Formation." Because the combination of the businesses that comprised the Moriah Group was a reorganization of entities under common control, the combination of these businesses has been reflected retroactively at carryover basis in these consolidated financial statements. The accounts presented for periods prior to the Legacy Formation transaction are those of the Moriah Group.

LRLP and its affiliated entities are referred to as Legacy in these financial statements.

LRLP, a Delaware limited partnership, was formed by its general partner, Legacy Reserves GP, LLC ("LRGPLLC"), on October 26, 2005 to own and operate oil and natural gas properties. LRGPLLC is a Delaware limited liability company formed on October 26, 2005, and it owns an approximately 0.1% general partner interest in LRLP.

Significant information regarding rights of the limited partners includes the following:

- Right to receive distributions of available cash within 45 days after the end of each quarter.
- No limited partner shall have any management power over our business and affairs; the general partner shall conduct, direct and manage LRLP's activities.
- The general partner may be removed if such removal is approved by the unitholders holding at least 66 $^{2}/_{3}$ percent of the outstanding units, including units held by LRLP's general partner and its affiliates.
- Right to receive information reasonably required for tax reporting purposes within 90 days after the close of the calendar year.

In the event of a liquidation, all property and cash in excess of that required to discharge all liabilities will be distributed to the unitholders and LRLP's general partner in proportion to their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of Legacy's assets in liquidation.

As used herein, the term Moriah Group refers to Moriah Resources, Inc. ("MRI"), Moriah Properties, Ltd. ("MPL"), the oil and natural gas interests individually owned by Dale A. and Rita Brown and the accounts of MBN Properties LP on a consolidated basis unless the context specifies otherwise. Prior to March 15, 2006, the accompanying financial statements include the accounts of the Moriah Group. From March 15, 2006, the accompanying financial statements also include the results of operations of the oil and natural gas properties acquired in the Legacy Formation transaction. All significant intercompany accounts and transactions have been eliminated. The Moriah Group consolidated MBN Properties LP as a variable interest entity under FASB FIN 46R since the Moriah Group was the primary beneficiary of MBN Properties LP. The partners, shareholders and owners of these entities have other investments, such as real estate, that are held either individually or through other legal entities that are not presented as part of these financial statements. The accompanying financial statements have been prepared on the accrual basis of accounting whereby revenues are recognized when earned, and expenses are recognized when incurred.

On July 22, 2005, MPL advanced $1,649,132 which was recorded as paid in capital and subordinated notes receivable to MBN Properties LP which utilized the capital to fund a deposit with The Prospective Investment and Trading Company, Ltd. ("PITCO") and its affiliates for the purchase of oil and natural gas properties described below. MPL also advanced $654,099 to fund the expenses of MBN Management LLC, the general partner of MBN Properties LP. Of this amount, $467 was for paid in capital and the balance of $653,632 was in a note receivable from MBN Management LLC. MBN Properties LP, a Delaware limited partnership, and MBN Management LLC, a

Delaware limited liability company, (collectively the MBN Group) were formed to acquire and operate oil and natural gas producing properties in partnership with Brothers Production Properties, Ltd., and certain third party investors. Cary D. Brown, the Executive Vice President of MRI and its 50% owner, is the Chief Executive Officer and a Director of MBN Management LLC. On September 14, 2005, MBN Properties LP purchased oil and natural gas producing properties located in the Permian Basin from PITCO and its affiliates for $66,151,723 (the PITCO Acquisition), subject to post-closing adjustments. While MBN Management LLC is a variable interest entity, the Moriah Group accounted for its interest in that entity using the equity method since it is not the primary beneficiary of MBN Management LLC under the expected losses test of paragraph 14 of FAS FIN 46R.

Legacy owns and operates oil and natural gas producing properties located primarily in the Permian Basin of West Texas and southeast New Mexico. Legacy has acquired oil and natural gas producing properties and drilled leasehold.

(b) Cash Equivalents

For purposes of the consolidated statement of cash flows, Legacy considers all highly liquid debt instruments with original maturities of three months or less to be cash equivalents.

(c) Trade Accounts Receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. Legacy routinely assesses the financial strength of its customers. Bad debts are recorded based on an account-by-account review after all means of collection have been exhausted and potential recovery is considered remote. Legacy does not have any off-balance-sheet credit exposure related to its customers (see Note 10).

(d) Oil and Natural Gas Properties

Legacy accounts for oil and natural gas properties by the successful efforts method. Under this method of accounting, costs relating to the acquisition of and development of proved areas are capitalized when incurred. The costs of development wells are capitalized whether productive or non-productive. Leasehold acquisition costs are capitalized when incurred. If proved reserves are found on an unproved property, leasehold cost is transferred to proved properties. Exploration dry holes are charged to expense when it is determined that no commercial reserves exist. Other exploration costs, including personnel costs, geological and geophysical expenses and delay rentals for oil and natural gas leases, are charged to expense when incurred. The costs of acquiring or constructing support equipment and facilities used in oil and gas producing activities are capitalized. Production costs are charged to expense as incurred and are those costs incurred to operate and maintain our wells and related equipment and facilities.

Depreciation and depletion of producing oil and natural gas properties is recorded based on units of production. FAS No. 19 requires that acquisition costs of proved properties be amortized on the basis of all proved reserves, developed and undeveloped, and that capitalized development costs (wells and related equipment and facilities) be amortized on the basis of proved developed reserves. As more fully described below, proved reserves are estimated annually by the Legacys independent petroleum engineer, LaRoche Petroleum Consultants, Ltd., and are subject to future revisions based on availability of additional information. Legacys in-house reservoir engineers prepare an updated estimate of reserves each quarter. Depletion is calculated each quarter based upon the latest estimated reserves data available. As discussed in Note 11, Legacy follows FAS No. 143. Under FAS No. 143, asset retirement

costs are recognized when the asset is placed in service, and are amortized over proved reserves using the units of production method. Asset retirement costs are estimated by Legacys engineers using existing regulatory requirements and anticipated future inflation rates.

Upon sale or retirement of complete fields of depreciable or depletable property, the book value thereof, less proceeds from sale or salvage value, is charged to income. On sale or retirement of an individual well the proceeds are credited to accumulated depletion and depreciation.

Oil and natural gas properties are reviewed for impairment when facts and circumstances indicate that their carrying value may not be recoverable. Legacy compares net capitalized costs of proved oil and natural gas properties to estimated undiscounted future net cash flows using management's expectations of future oil and natural gas prices. These future price scenarios reflect Legacy's estimation of future price volatility. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, using estimated discounted future net cash flows based on management's expectations of future oil and natural gas prices. For the year ended December 31, 2008, Legacy recognized $76.9 million of impairment expense on 101 separate producing fields related primarily to the decline in oil and natural gas prices during the year. For the year ended December 31, 2007, Legacy recognized $3.2 million of impairment expense on 43 separate producing fields related primarily to the decline in performance on individual properties. For the year ended December 31, 2006, Legacy recognized $16.1 million of impairment expense on 41 separate producing fields related primarily to the decline in natural gas and oil prices from the dates at which the purchase prices for the PITCO acquisition and the formation transaction were allocated among the purchased properties.

Unproven properties that are individually significant are assessed for impairment and if considered impaired are charged to expense when such impairment is deemed to have occurred. Costs related to unproved mineral interests that are individually insignificant are amortized over the shorter of the exploratory period or the lease/ concession holding period which is typically three years in the Permian Basin.

(e) Oil and Natural Gas Reserve Quantities

Legacy's estimate of proved reserves is based on the quantities of oil and natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. LaRoche Petroleum Consultants, Ltd. prepares a reserve and economic evaluation of all Legacy's properties on a well-by-well basis utilizing information provided to it by Legacy and information available from state agencies that collect information reported to it by the operators of Legacy's properties.

Reserves and their relation to estimated future net cash flows impact Legacy's depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. Legacy prepares its reserve estimates, and the projected cash flows derived from these reserve estimates, in accordance with SEC guidelines. The independent engineering firm described above adheres to the same guidelines when preparing their reserve report. The accuracy of Legacy's reserve estimates is a function of many factors including the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgments of the individuals preparing the estimates.

Legacy's proved reserve estimates are a function of many assumptions, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of oil, natural gas, and natural gas liquids eventually recovered.

(f) Income Taxes

Legacy is structured as a limited partnership, which is a pass-through entity for United States income tax purposes.

In May 2006, the State of Texas enacted a new margin-based franchise tax law that replaced the existing franchise tax. This new tax is commonly referred to as the Texas margin tax and is assessed at a 1% rate. Corporations, limited partnerships, limited liability companies, limited liability partnerships and joint ventures are examples of the types of entities that are subject to the new tax. The tax is considered an income tax and is determined by applying a tax rate to a base that considers both revenues and expenses. The Texas margin tax became effective for franchise tax reports due on or after January 1, 2008.

Legacy recorded income tax expense of $48,148 and $337,000 for the years ended December 31, 2008 and 2007, respectively, which consists primarily of the Texas margin tax and federal income tax on a corporate subsidiary which employs full and part-time personnel providing services to the Partnership. The Partnership's total effective tax rate differs from statutory rates for federal and state purposes primarily due to being structured as a limited partnership, which is a pass-through entity for federal income tax purposes.

Net income for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under the partnership agreement. In addition, individual unitholders have different investment bases depending upon the timing and price of acquisition of their common units, and each unitholder's tax accounting, which is partially dependent upon the unitholder's tax position, differs from the accounting followed in the consolidated financial statements. As a result, the aggregate difference in the basis of net assets for financial and tax reporting purposes cannot be readily determined as the Partnership does not have access to information about each unitholder's tax attributes in the Partnership. However, with respect to the Partnership, the Partnership's book basis in its net assets exceeds the Partnership's net tax basis by $558.4 million at December 31, 2008.

(g) Derivative Instruments and Hedging Activities

Legacy uses derivative financial instruments to achieve a more predictable cash flow from its oil and natural gas production by reducing its exposure to price fluctuations and interest rate changes. Legacy accounts for these activities pursuant to FAS No. 133 "*Accounting for Derivative Instruments and Hedging Activities,* as amended. This statement establishes accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded at fair market value and included in the balance sheet as assets or liabilities.

Legacy does not specifically designate derivative instruments as cash flow hedges, even though they reduce its exposure to changes in oil and natural gas prices and interest rate changes. Therefore, the mark-to-market of oil, NGL and natural gas derivatives are recorded in current earnings. Changes in the fair values of interest rate derivatives are recorded in interest expense (see Note 9).

(h) Use of Estimates

Management of Legacy has made a number of estimates and assumptions relating to the reporting of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities to prepare these consolidated financial statements in conformity with accounting principles generally accepted in the United States of America. Actual results could differ materially from those estimates. Estimates which are particularly significant to the consolidated financial statements include estimates of oil and natural gas reserves, valuation of derivatives, future cash flows from oil and natural gas properties, depreciation, depletion and amortization and asset retirement obligations.

(i) Revenue Recognition

Sales of crude oil, natural gas liquids and natural gas are recognized when the delivery to the purchaser has occurred and title has been transferred. This occurs when oil or natural gas has been delivered to a pipeline or a tank lifting has occurred. Crude oil is priced on the delivery date based upon prevailing prices published by purchasers with certain adjustments related to oil quality and physical location. Virtually all of Legacy’s natural gas contracts’ pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of natural gas, and prevailing supply and demand conditions, so that the price of the natural gas fluctuates to remain competitive with other available natural gas supplies. These market indices are determined on a monthly basis. As a result, Legacy’s revenues from the sale of oil and natural gas will suffer if market prices decline and benefit if they increase. Legacy believes that the pricing provisions of its oil and natural gas contracts are customary in the industry.

Legacy currently uses the “net-back” method of accounting for transportation arrangements of its natural gas sales. Legacy sells natural gas at the wellhead and collects a price and recognizes revenues based on the wellhead sales price since transportation costs downstream of the wellhead are incurred by its purchasers and reflected in the wellhead price. Legacy’s contracts with respect to the sale of its natural gas produced, with one immaterial exception, provide Legacy with a net price payment. That is, when Legacy is paid for its natural gas by its purchasers, Legacy receives a price which is net of any costs incurred for treating, transportation, compression, etc. In accordance with the terms of Legacy’s contracts, the payment statements Legacy receives from its purchasers show a single net price without any detail as to treating, transportation, compression, etc. Thus, Legacy’s revenues are recorded at this single net price.

Natural gas imbalances occur when Legacy sells more or less than its entitled ownership percentage of total natural gas production. Any amount received in excess of its share is treated as a liability. If Legacy receives less than its entitled share the underproduction is recorded as a receivable. Legacy did not have any significant natural gas imbalance positions as of December 31, 2008, 2007 or 2006.

Legacy is paid a monthly operating fee for each well it operates for outside owners. The fee covers monthly general and administrative costs. As the operating fee is a reimbursement of costs incurred on behalf of third parties, the fee has been netted against general and administrative expense.

(j) Investments

Undivided interests in oil and natural gas properties owned through joint ventures are consolidated on a proportionate basis. Investments in entities where Legacy exercises significant influence, but not a controlling interest are accounted for by the equity method. Under the equity method, Legacy’s investments are stated at cost plus the equity in undistributed earnings and losses after acquisition.

(k) Intangible assets

Legacy has capitalized certain operating rights acquired in the acquisition of oil and gas properties (Note 4). The operating rights, which have no residual value, are amortized over their estimated economic life of approximately 15 years beginning July 1, 2006. Amortization expense is included as an element of depletion, depreciation, amortization and accretion expense. Impairment will be assessed on a quarterly basis or when there is a material change in the remaining useful life. The expected amortization expense for 2009, 2010, 2011, 2012 and 2013 is $537,000, $522,000, $510,000, $502,000 and $498,000, respectively.

(l) Environmental

Legacy is subject to extensive federal, state and local environmental laws and regulations. These laws, which are frequently changing, regulate the discharge of materials into the environment and may require Legacy to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a non-capital nature are recorded when environmental assessment and/ or remediation are probable, and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable.

(m) Earnings (Loss) Per Unit

Legacy computes its earnings (loss) per unit in accordance with SFAS No. 128, *Earnings per Share*. Basic earnings per unit amounts are calculated using the weighted average number of units outstanding during each period. Diluted earnings per unit also give effect to dilutive unvested restricted units (calculated based upon the treasury stock method) (Note 12).

(n) Redemption of Units

Units redeemed are recorded at cost.

(o) Segment Reporting

Legacys management treats each new acquisition of oil and natural gas properties as a separate operating segment. Legacy aggregates these operating segments into a single segment for reporting purposes.

(p) Unit-Based Compensation

Concurrent with the Formation Transaction on March 15, 2006, a Long-Term Incentive Plan (LTIP) for Legacy was created and Legacy adopted SFAS No. 123(R), *Share-Based Payment*. Due to Legacys history of cash settlements for option exercises, Legacy accounts for unit options under the liability method of SFAS No. 123(R). This method requires the Partnership to recognize the fair value of each unit option at the end of each period. Expense is recognized as a change in the liability from period to period. Pursuant to the provisions of SFAS 123(R), Legacys issued units, as reflected in the accompanying consolidated balance sheet at December 31, 2008, do not include 25,040 units related to unvested restricted unit awards.

(q) Recently Issued Accounting pronouncements

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 157, *Fair Value Measurements*. Statement No. 157 defines fair value as used in numerous accounting pronouncements, establishes a framework for measuring fair value in GAAP and expands disclosure related to the use of fair value measures in financial statements. We adopted the Statement effective January 1, 2008 and the adoption did not have a significant effect on our consolidated results of operations, financial position or cash flows. See Note 8 for other disclosures required by Statement No. 157.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* (SFAS 141(R)), which replaces FASB Statement No. 141. SFAS 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non-controlling interest in the acquiree and the goodwill acquired. The Statement also establishes disclosure requirements that will enable users to evaluate the nature and financial effects of the business combination.

SFAS 141(R) is effective for acquisitions that occur in an entitys fiscal year that begins after December 15, 2008, which will be Legacys fiscal year 2009. The impact, if any, will depend on the nature and size of business combinations we consummate after the effective date.

In December 2007, the FASB issued SFAS No. 160, Non-controlling Interests in Consolidated Financial Statements an amendment of ARB No. 51 (SFAS 160). SFAS 160 requires that accounting and reporting for minority interests will be re-characterized as non-controlling interests and classified as a component of equity. SFAS 160 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners. SFAS 160 applies to all entities that prepare consolidated financial statements, except not-for-profit organizations, but will affect only those entities that have an outstanding non-controlling interest in one or more subsidiaries or that deconsolidate a subsidiary. This statement is effective as of the beginning of an entitys first fiscal year beginning after December 15, 2008, which will be Legacys fiscal year 2009. Based upon the December 31, 2008 balance sheet, the statement would have no impact.

In March, 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities* (SFAS 161). SFAS 161 amends and expands the disclosure requirements of FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities*. SFAS 161 requires disclosures related to objectives and strategies for using derivatives; the fair-value amounts of, and gains and losses on, derivative instruments; and credit-risk-related contingent features in derivative agreements. This statement is effective as of the beginning of an entitys fiscal year beginning after December 15, 2008, which will be the Partnerships fiscal year 2009. The effect on the Partnerships disclosures for derivative instruments as a result of the adoption of SFAS 161 in 2009 will depend on the Partnerships derivative instruments and hedging activities at that time.

During May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles* (SFAS 162). SFAS 162 identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements presented in conformity with GAAP. SFAS 162 is effective 60 days following the SECs approval of the Public Company Accounting Oversight Board amendments to AU Section 411, *The Meaning of* Present Fairly in Conformity With Generally Accepted Accounting Principles. We do not expect that the adoption of SFAS 162 will have a significant impact on our financial statements.

In June 2008, the FASB issued FASB Staff Position No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* (FSP 03-6-1), which addresses whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the net income allocation in computing basic net income per share under the two class method prescribed under SFAS 128, *Earnings per Share*. FSP 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and, to the extent applicable, must be applied retrospectively by adjusting all prior-period net income per share data to conform to the provisions of the standard. The adoption of FSP 03-6-1 is not expected to have a material effect on our net income per common unit calculations.

In December 2008, the SEC released Final Rule, *Modernization of Oil and Gas Reporting*. The new disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes. The new requirements also will allow companies to disclose their probable and possible reserves to investors. In addition, the new disclosure requirements require companies to: (a) report the independence and qualifications of its reserves preparer or auditor; (b) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserves audit; and (c) report oil and natural gas reserves using an average price based upon the prior 12-month period rather than year-end prices. The use of average prices will affect future impairment and depletion calculations. The new disclosure requirements are effective for annual reports on Forms 10-K for fiscal years ending on or after December 31, 2009. Legacy is currently assessing the impact that adoption of this rule will have on its financial statements, which will vary depending on changes in commodity prices.

(r) Prior Year Financial Statement Presentation

Certain prior year balances have been reclassified to conform to the current year presentation of balances as stated in this annual report on Form 10-K.

(2) Fair Values of Financial Instruments

The estimated fair values of Legacys financial instruments closely approximate the carrying amounts as discussed below:

Cash and cash equivalents, accounts receivable, other current assets, accounts payable and other current liabilities. The carrying amounts approximate fair value due to the short maturity of these instruments.

Debt. The carrying amount of the revolving long-term debt approximates fair value because Legacys current borrowing rate does not materially differ from market rates for similar bank borrowings.

Commodity price derivatives. The fair market values of commodity derivative instruments are estimated based upon the current market price of the respective commodities at the date of valuation. They represent the amount which Legacy would be required to pay or able to receive, based upon the differential between a fixed and a variable commodity price as specified in the hedge contracts.

Interest rate derivatives. The fair market values of interest rate derivative instruments are estimated based upon the current market LIBOR rates for the respective notional amount at the date of valuation. It represents the difference between the fixed rate as specified in the hedge contracts and the floating rate applicable to the notional amounts.

(3) Credit Facility

As an integral part of the formation of Legacy, Legacy entered into a credit agreement with a senior credit facility (the Legacy Facility). Legacy has pledged oil and natural gas properties as collateral for borrowings under the Legacy Facility. The initial terms of the Legacy Facility permitted borrowings in the lesser amount of (i) the borrowing base, or (ii) $300 million, increased to $500 million pursuant to the Third Amendment effective October 24, 2007. The borrowing base under the Legacy Facility, $410 million as of December 31, 2008, was initially set at $130 million. Pursuant to the Fourth Amendment to the credit agreement, the borrowing base was initially increased to $272 million as of April 24, 2008 and further increased to $320 million coincident with the closing of the COP III Acquisition, which closed on April 30, 2008. On October 6, 2008, the borrowing base was increased to $383.76 million pursuant to the Fifth Amendment and further increased to $410 million with the addition of two additional banks to the credit facility. The borrowing base is re-determined every six months and will be adjusted based upon changes in the fair market value of Legacys oil and natural gas assets. Under the Legacy Facility, as amended, interest on debt outstanding is charged based on Legacys selection of a LIBOR rate plus 1.50% to 2.125%, or the alternate base rate (ABR) which equals the higher of the prime rate or the Federal funds effective rate plus 0.50%, plus an applicable margin between 0% and 0.50%.

As of December 31, 2008, Legacy had outstanding borrowings of $282 million at a weighted average interest rate of 5.08%. Thus, Legacy had approximately $128 million of availability remaining. For the year ended December 31, 2008, Legacy paid $8.8 million of interest expense on the Legacy Facility. The Legacy Facility contains certain loan covenants requiring minimum financial ratio coverages, involving the current ratio and EBITDA to interest expense as well as acceleration in term due to changes in control and restrictions on our ability to make distributions other than from available cash. At December 31, 2008, Legacy was in compliance with all aspects of the Legacy Facility.

Long-term debt consists of the following at December 31, 2008 and 2007:

	December 31, 2008	December 31, 2007
	(In thousands)	
Legacy Facility-due March 2010	$282,000	$ 110,000

(4) Acquisitions

Legacy Formation Acquisition

On March 15, 2006, LRLP completed a private equity offering in which it issued 5,000,000 limited partnership units at a gross price of $17.00 per unit, netting $76.8 million after initial purchaser's discount, placement agent fees and expenses. Simultaneous with the completion of this offering, Legacy purchased the oil and natural gas properties of the Moriah Group, Brothers Group, H2K Holdings Ltd. and the Charitable Support Foundations, Inc. and its affiliates. Legacy also purchased the oil and natural gas properties owned by MBN Properties, LP. In the case of the Moriah Group, the Brothers Group and H2K Holdings Ltd. those entities exchanged their oil and natural gas properties for limited partnership units. The purchase of the oil and natural gas properties owned by the charitable foundations was solely for cash of $7.7 million. The owners of the Moriah Group, the Brothers Group and H2K Holdings Ltd. (the "Founding Investors") exchanged 4.4 million of their units for $69.9 million in cash. The Moriah Group has been treated as the acquiring entity in the Legacy Formation. Accordingly, the accounts of the businesses acquired from the Moriah Group have been reflected retroactively at carryover basis in the consolidated financial statements, and the units issued to acquire them have been accounted for as a recapitalization. The net assets of the other businesses acquired and the units issued in exchange for them have been reflected at fair value and included in the statement of operations from the date of acquisition. With the exception of its assumption of liabilities associated with the oil and natural gas swaps it acquired, the other depreciable assets of the Brothers Group (office furniture and equipment and vehicles) and certain unamortized deferred financing costs of the Moriah Group, LRLP did not acquire any other assets or liabilities of the Moriah Group, the Brothers Group, H2K Holdings Ltd. or the Charitable Support Foundations, Inc. and its affiliates. The removal of the other assets and liabilities of the Moriah Group was reflected as a deemed dividend in Legacy's December 31, 2006 consolidated statement of unitholders' equity.

The following table sets forth the units issued in the Legacy Formation transaction:

	Number of Units
MPL	7,334,070
DAB Resources, Ltd.	859,703
Moriah Group	8,193,773
Brothers Group	6,200,358
H2K Holdings Ltd.	83,499
MBN Properties LP	3,162,438
LRLP units	600,000
Total units issued at Legacy Formation	18,240,068

In addition to the 18,240,068 units issued at Legacy Formation, 52,616 restricted management units were issued to employees of Legacy concurrent with, but not as a part of, the Legacy Formation.

The following table sets forth the purchase price of the oil and natural gas properties purchased from the Brothers Group, H2K Holdings Ltd. and three charitable foundations, which included the assumption of liabilities associated with oil and natural gas swaps as of March 14, 2006:

	Number of Units at $17.00 per Unit	Purchase Price of Assets Acquired
Brothers Group	6,200,358	$105,406,069
H2K Holdings Ltd.	83,499	1,419,483
Cash paid to three charitable foundations		7,682,854
Total purchase price before liabilities assumed		114,508,406
Plus:		
Oil and natural gas swap liabilities assumed		3,147,152
Asset retirement obligations incurred		1,467,241
Less:		
Office furniture, equipment and vehicles acquired		(107,275)
Total purchase price allocated to oil and natural gas properties acquired		$119,015,524

In addition to the 3,162,438 common units issued to MBN Properties LP as part of the Legacy Formation transaction, LRLP paid $65.3 million in cash to MBN Properties LP to acquire that portion of the oil and natural gas properties of MBN Properties LP it did not already own by virtue of the Moriah Groups ownership of a 46.22% limited partnership interest in MBN Properties LP. In addition, LRLP paid $1,980,468 to MBN Management LLC to reimburse expenses incurred by that entity in anticipation of the Legacy Formation. The following table sets forth the calculation of the step-up of oil and natural gas property basis with respect to this interest acquired:

	Number of Units at $17.00 per Unit	Purchase Price of Assets Acquired
Units issued to MBN Properties LP	3,162,438	$ 53,761,446
Cash paid to MBN Properties LP		65,300,000
Total purchase price before liabilities assumed		119,061,446
Plus:		
Oil and natural gas swap liabilities assumed		2,539,625
ARO liabilities assumed		453,913
Less:		
Net book value of other property and equipment on MBN Properties LP at March 14, 2006		(39,056)
		122,015,928
Less:		
Net book value of oil and gas assets on MBN Properties LP at March 14, 2006		(62,990,390)
Purchase price in excess of net book value of assets		59,025,538
Less:		
Share already owned by Moriah via consolidation of MBN Properties LP	46.22%	(27,281,604)
Non-controlling interest share to record(a)		31,743,934
Plus:		
Elimination of deferred financing costs related to non-controlling interests share of MBN Properties LP		164,202
Reimbursement of Brothers Groups share of MBN Management LLC losses from inception through March 14, 2006		780,239

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Number of Units at $17.00 per Unit	Purchase Price of Assets Acquired
MBN Properties LP purchase price to allocate to oil and natural gas properties		$ 32,688,375
Units related to purchase of non-controlling interest(a)	1,867,290	
Units related to interest previously owned by Moriah Group	1,295,148	
Total units issued to MBN Properties LP	3,162,438	

Larron Acquisition

On June 29, 2006, Legacy purchased a 100% working interest and an approximate 82% net revenue interest in producing leases located in the Farmer Field for $5,700,000. The conveyance of the leases is effective April 1, 2006. The $5.6 million net purchase price was allocated with $4.6 million recorded as lease and well equipment and $1.0 million of leasehold costs. Asset retirement obligations in the amount of $328,867 were recognized in connection with this acquisition. The operations of these Farmer Field properties are included from their acquisition on June 29, 2006 in Legacys statement of operations for the year ended December 31, 2006.

South Justis Unit Acquisition

On June 29, 2006, Legacy purchased Henry Holding LPs 15.0% working interest and a 13.1% net revenue interest in the South Justis Unit (SJU), two leases not in the unit, each with one well, adjacent to the SJU and the right to operate these properties. The stated purchase price was $14 million cash plus the issuance of 138,000 units on June 29, 2006 and 8,415 units on November 10, 2006 at their estimated fair value of $17.00 per unit ($2,346,000 and $143,055, respectively) less final adjustments of approximately $624,000. The effective date of Legacys ownership was May 1, 2006. The operating results from this acquisition have been included from July 1, 2006. The properties acquired are located in Lea County, New Mexico where Legacy owns other producing properties. Legacy has been elected operator of the SJU following the closing of the transaction, which entitles Legacy to a contractual overhead reimbursement of approximately $127,500 per month from its partners in the SJU. The $15.9 million net purchase price was allocated with $2.9 million recorded as lease and well equipment, $6.0 million of leasehold costs and $7.0 million capitalized as an intangible asset relating to the contract operating rights. The capitalized operating rights will be amortized over the estimated total well months the wells in the SJU are expected to be operated. Asset retirement obligations in the amount of $137,453 were recognized in connection with this acquisition. The operations of the South Justis Unit are included from the acquisition on June 29, 2006 in Legacys statement of operations for the year ended December 31, 2006.

Kinder Morgan Acquisition

On July 31, 2006, Legacy purchased certain oil and natural gas properties located in the Permian Basin from Kinder Morgan for a net purchase price of $17.2 million. The effective date of this purchase was July 1, 2006. The $17.2 million purchase price was allocated with $4.1 million recorded as lease and well equipment and $13.1 million of leasehold costs. Asset retirement obligations of $1,383,180 were recorded in connection with this acquisition. The operations of these Kinder Morgan Acquisition properties are included from their acquisition on July 31, 2006 in Legacys statement of operations for the year ended December 31, 2006.

Binger Acquisition

On April 16, 2007, Legacy purchased certain oil and natural gas properties and other interests in the East Binger (Marchand) Unit in Caddo County, Oklahoma from Nielson & Associates, Inc. for a net purchase price of $44.2 million (Binger Acquisition). The purchase price was paid with the issuance of 611,247 units valued at $15.8 million and $28.4 million paid in cash. The effective date of this purchase was February 1, 2007. The $44.2 million purchase price was allocated with $14.7 million recorded as lease and well equipment, $29.4 million

LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of leasehold costs and $0.1 million as investment in equity method investee related to the 50% interest acquired in Binger Operations, LLC. Asset retirement obligations of $184,636 were recorded in connection with this acquisition. The operations of these Binger Acquisition properties have been included from their acquisition on April 16, 2007.

Ameristate Acquisition

On May 1, 2007, Legacy purchased certain oil and natural gas properties located in the Permian Basin from Ameristate Exploration, LLC for a net purchase price of $5.2 million (Ameristate Acquisition). The effective date of this purchase was January 1, 2007. The $5.2 million purchase price was allocated with $0.5 million recorded as lease and well equipment and $4.7 million of leasehold costs. Asset retirement obligations of $51,414 were recorded in connection with this acquisition. The operations of these Ameristate Acquisition properties have been included from their acquisition on May 1, 2007.

TSF Acquisition

On May 25, 2007, Legacy purchased certain oil and natural gas properties located in the Permian Basin from Terry S. Fields for a net purchase price of $14.7 million (TSF Acquisition). The effective date of this purchase was March 1, 2007. The $14.7 million purchase price was allocated with $1.8 million recorded as lease and well equipment and $12.9 million of leasehold costs. Asset retirement obligations of $99,094 were recorded in connection with this acquisition. The operations of these TSF Acquisition properties have been included from their acquisition on May 25, 2007.

Raven Shenandoah Acquisition

On May 31, 2007, Legacy purchased certain oil and natural gas properties located in the Permian Basin from Raven Resources, LLC and Shenandoah Petroleum Corporation for a net purchase price of $13.0 million (Raven Shenandoah Acquisition). The effective date of this purchase was May 1, 2007. The $13.0 million purchase price was allocated with $6.0 million recorded as lease and well equipment and $7.0 million of leasehold costs. Asset retirement obligations of $378,835 were recorded in connection with this acquisition. The operations of these Raven Shenandoah Acquisition properties have been included from their acquisition on May 31, 2007.

Raven OBO Acquisition

On August 3, 2007, Legacy purchased certain oil and natural gas properties located primarily in the Permian Basin from Raven Resources, LLC and private parties for a net purchase price of $20.0 million (Raven OBO Acquisition). The effective date of this purchase was July 1, 2007. The $20.0 million purchase price was allocated with $1.6 million recorded as lease and well equipment and $18.4 million of leasehold costs. Asset retirement obligations of $224,329 were recorded in connection with this acquisition. The operations of these Raven OBO Acquisition properties have been included from their acquisition on August 3, 2007.

TOC Acquisition

On October 1, 2007, Legacy purchased certain oil and natural gas properties located in the Texas Panhandle from The Operating Company, et al, for a net purchase price of $60.6 million (TOC Acquisition). The effective date of this purchase was September 1, 2007. The $60.6 million purchase price was allocated with $23.7 million recorded as lease and well equipment and $36.9 million of leasehold costs. Asset retirement obligations of $1.6 million were recorded in connection with this acquisition. The operations of these TOC Acquisition properties have been included from their acquisition on October 1, 2007.

LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Summit Acquisition

Also on October 1, 2007, Legacy purchased certain oil and natural gas properties located in the Permian Basin from Summit Petroleum Management Corporation for a net purchase price of $13.5 million (Summit Acquisition). The effective date of this purchase was September 1, 2007. The $13.5 million purchase price was allocated with $2.1 million recorded as lease and well equipment and $11.3 million as leasehold cost. Asset retirement obligations of $128,705 were recorded in connection with this acquisition. The operations of these Summit Acquisition properties have been included from their acquisition on October 1, 2007.

COP III Acquisition

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 operations of these COP III Acquisition properties have been included from their acquisition on April 30, 2008.

Reeves Unit Exchange

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 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, Legacys 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.

Pantwist Acquisition

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 of 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.

Pro Forma Operating Results

The following table reflects the unaudited pro forma results of operations as though the Formation Transactions, Farmer Field, South Justis Unit and Kinder Morgan had occurred on January 1, 2006. The table also reflects the unaudited pro forma results of operations as though the Binger, Ameristate, TSF, Raven Shenandoah, Raven

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OBO, TOC and Summit acquisitions had occurred on January 1, 2006 and 2007 and reflects the unaudited pro forma results of operations as though the COP III and Pantwist acquisitions had each occurred on January 1, 2006, 2007 and 2008. The pro forma amounts are not necessarily indicative of the results that may be reported in the future:

	December 31,		
	2008	2007	2006
		(In thousands)	
Revenues	$230,448	$160,241	$ 115,414
Net income (loss)	$163,229	$ (48,420)	$ 12,844
Income (loss) per unit basic and diluted	$ 5.26	$ (1.75)	$ 0.68
Units used in computing income (loss) per unit:			
basic	31,037	27,676	19,004
diluted	31,057	27,676	19,006

(5) Related Party Transactions

Cary D. Brown, Legacys Chairman and Chief Executive Officer, and Kyle A. McGraw, Legacys Executive Vice President Business Development and Land, own partnership interests which, in turn, own a combined non-controlling 4.16% interest as limited partners in the partnership which owns the building that Legacy occupies. Monthly rent is $14,808, without respect to property taxes and insurance. The lease expires in August 2011.

The Moriah Group did not directly employ any persons or directly incur any office overhead. Substantially all general and administrative services were provided by Petroleum Strategies, Inc. which employed all personnel and paid for all employee salaries, benefits, and office expenses. Petroleum Strategies Inc. charged the Moriah Group for such services in an amount which was intended to be equal to the actual expenses it incurred. The amount charged was $445,267 for the year ended December 31, 2006. On April 1, 2006 following the Legacy Formation, certain employees of Petroleum Strategies, Inc. and Brothers Production Company Inc. became employees of Legacy. For the period from March 15, 2006 to December 31, 2006, Brothers Production Company Inc. provided $47,236 of transition administrative services to Legacy.

Legacy uses Lynch, Chappell and Alsup for legal services. Alan Brown, son of Dale Brown and brother of Cary Brown, is a less than ten percent shareholder in this firm. Legacy paid legal fees of $100,392, $127,313 and $40,392 for the years ended December 31, 2008, 2007 and 2006, respectively.

(6) Commitments and Contingencies

From time to time Legacy is a party to various legal proceedings arising in the ordinary course of business. While the outcome of lawsuits cannot be predicted with certainty, Legacy is not currently a party to any proceeding that it believes, if determined in a manner adverse to Legacy, could have a potential material adverse effect on its financial condition, results of operations or cash flows. Legacy believes the likelihood of such a future event to be remote.

Additionally, Legacy is subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes environmental protection requirements that result in increased costs to the oil and natural gas industry in general, the business and prospects of Legacy could be adversely affected.

Legacy has employment agreements with its officers that specify that if the officer is terminated by Legacy for other than cause or following a change in control, the officer shall receive severance pay ranging from 24 to 36 months salary plus bonus and COBRA benefits.

LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

On September 24, 2008, Legacy entered into a participation agreement with Black Oak Resources, LLC committing up to $20 million over three years to jointly invest in and develop oil and natural gas properties. Unless Black Oak Resources, LLC were to increase the $110 million of equity commitments initially committed or enter into a borrowing relationship, Legacys obligations are expected to be in the range of $8 million over the next three years.

(7) Business and Credit Concentrations

Cash

Legacy maintains its cash in bank deposit accounts, which, at times, may exceed federally insured amounts. Legacy has not experienced any losses in such accounts. Legacy believes it is not exposed to any significant credit risk on its cash.

Revenue and Trade Receivables

Substantially all of Legacys accounts receivable result from oil and natural gas sales or joint interest billings to third parties in the oil and natural gas industry. This concentration of customers and joint interest owners may impact Legacys overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. Historically, Legacy has not experienced significant credit losses on such receivables. No bad debt expense was recorded in 2008, 2007, or 2006. Legacy cannot ensure that such losses will not be realized in the future. A listing of oil and natural gas purchasers exceeding 10% of Legacys sales is presented in Note 10.

Commodity Derivatives

Due to the volatility of oil and natural gas prices, Legacy periodically enters into price-risk management transactions (e.g., swaps or collars) for a portion of its oil and natural gas production to achieve a more predictable cash flow, as well as to reduce exposure from price fluctuations. Legacy values these transactions at fair value on a recurring basis (Note 8). As of December 31, 2008, all of Legacys commodity derivative transactions have a fair value in favor of the Partnership of $134 million, collectively. Legacy enters into commodity derivative transactions with members of its revolving credit facility, who Legacys management believes are major, creditworthy financial institutions. In addition, we review and asses the creditworthiness of these institutions on a routine basis.

(8) Fair Value Measurements

Legacy adopted SFAS No. 157, *Fair Value Measurements*, effective January 1, 2008 for financial assets and liabilities measured at fair value on a recurring basis. In February 2008, the FASB issued FSP No. 157-2, which delayed the effective date of SFAS No. 157 by one year for non-financial assets and liabilities. As defined in SFAS No. 157, fair value is the price that would be received upon the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. SFAS No. 157 requires disclosure that establishes a framework for measuring fair value and expands disclosure about fair value measurements. The statement requires fair value measurements be classified and disclosed in one of the following categories:

Level 1: Measured based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. Legacy considers active markets as those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2: Measured based on quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that Legacy values using observable market data. Substantially all of these inputs are observable in the marketplace throughout the term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange traded derivatives such as over-the-counter commodity price swaps and interest rate swaps.

Level 3: Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e. supported by little or no market activity). Legacys valuation models are primarily industry standard models that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, and (c) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Level 3 instruments primarily include derivative instruments, such as basis swaps, NGL derivative swaps, natural gas derivative swaps for those derivatives that are indexed to the West Texas Waha and ANR-Oklahoma indices and commodity collars. Although Legacy utilizes third party broker quotes to assess the reasonableness of our prices and valuation techniques, Legacy does not have sufficient corroborating evidence to support classifying these assets and liabilities as Level 2.

As required by SFAS No. 157, financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The following table summarizes the valuation of our investments and financial instruments by SFAS No. 157 pricing levels as of December 31, 2008:

	Fair Value Measurements at December 31, 2008 Using			
Description	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value as of December 31, 2008
		(In thousands)		
Oil, NGL and natural gas derivative swaps	$	$ 105,920	$ 13,619	$ 119,539
Oil collars			15,366	15,366
Interest rate swaps		(10,459)		(10,459)
Total	$	$ 95,461	$ 28,985	$ 124,446

The determination of the fair values above incorporates various factors required under SFAS 157. These factors include the impact of our non-performance risk and the credit standing of the counterparties involved in the Partnerships derivative contracts. The risk of nonperformance by the Partnerships counterparties is mitigated by the fact that such counterparties (or their affiliates) are also bank lenders under the Partnerships revolving credit facility. In addition, Legacy routinely monitors the creditworthiness of its counterparties.

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as level 3 in the fair value hierarchy:

	Significant Unobservable Inputs (Level 3) (In thousands)
Balance January 1, 2008	$ (4,502)
Total gains or (losses)	32,005
Settlements	1,482

Transfers	
Balance as of December 31, 2008	$ 28,985
Change in unrealized gains (losses) included in earnings relating to derivatives still held as of December 31, 2008	$ 33,487

During periods of market disruption, including periods of volatile oil and natural gas prices, rapid credit contraction or illiquidity, it may be difficult to value certain of the Partnerships derivative instruments if trading becomes less frequent and/or market data becomes less observable. There may be certain asset classes that were in active markets with observable data that become illiquid due to changes in the financial environment. In such cases, more derivative instruments may fall to Level 3 and thus require more subjectivity and management judgment. As such, valuations may include inputs and assumptions that are less observable or require greater estimation as well as valuation methods which are more sophisticated or require greater estimation thereby resulting in valuations with less certainty. Further, rapidly changing commodity and unprecedented credit and equity market conditions could materially impact the valuation of derivative instruments as reported within our consolidated financial statements and the period-to-period changes in value could vary significantly. Decreases in value may have a material adverse effect on our results of operations or financial condition.

(9) Derivative Financial Instruments

Commodity derivatives

Due to the volatility of oil and natural gas prices, Legacy periodically enters into price-risk management transactions (e.g., swaps or collars) for a portion of its oil and natural gas production to achieve a more predictable cash flow, as well as to reduce exposure from price fluctuations. While the use of these arrangements limits Legacys ability to benefit from increases in the price of oil and natural gas, it also reduces Legacys potential exposure to adverse price movements. Legacys arrangements, to the extent it enters into any, apply to only a portion of its production, provide only partial price protection against declines in oil and natural gas prices and limit Legacys potential gains from future increases in prices. None of these instruments are used for trading or speculative purposes.

All of these price risk management transactions are considered derivative instruments and accounted for in accordance with SFAS No. 133 *Accounting for Derivative Instruments and Hedging Activities*. These derivative instruments are intended to mitigate a portion of Legacys price-risk and may be considered hedges for economic purposes but Legacy has chosen not to designate them as cash flow hedges for accounting purposes. Therefore, all derivative instruments are recorded on the balance sheet at fair value with changes in fair value being recorded in current period earnings.

By using derivative instruments to mitigate exposures to changes in commodity prices, Legacy exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes Legacy, which creates repayment risk. Legacy minimizes the credit or repayment risk in derivative instruments by entering into transactions with high-quality counterparties.

For the years ended December 31, 2008, 2007, and 2006, Legacy recognized realized and unrealized gains (losses) related to its oil, NGL and natural gas derivatives. The impact on net income from commodity derivative activities was as follows:

	December 31,		
	2008	2007 (In thousands)	2006
Crude oil derivative contract settlements	$ (38,185)	$ (3,627)	$ (6,667)
Natural gas liquid derivative contract settlements	(3,025)	(619)	
Natural gas derivative contract settlements	977	4,457	6,405
Total derivative contract settlements	(40,233)	211	(262)
Unrealized change in fair value oil contracts	195,909	(76,484)	4,338
Unrealized change in fair value natural gas liquid contracts	4,537	(3,228)	
Unrealized change in fair value natural gas contracts	16,730	(5,655)	5,213
Total unrealized change in fair value	217,176	(85,367)	9,551
Total realized and unrealized gains (losses) on derivative contracts	$ 176,943	$ (85,156)	$ 9,289

In September 2006, Legacy paid its counterparty $4 million to cancel and reset oil swaps for 372,000 barrels in 2007 from $60.00 to $65.82 per barrel and for 348,000 barrels in 2008 from $60.50 to $66.44 per barrel.

As of December 31, 2008, Legacy had the following NYMEX West Texas Intermediate crude oil swaps paying floating prices and receiving fixed prices for a portion of its future oil production as indicated below:

Calendar Year	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
2009	1,488,969	$82.82	$ 61.05 - $140.00
2010	1,397,973	$82.37	$ 60.15 - $140.00
2011	1,155,712	$88.07	$ 67.33 - $140.00
2012	969,812	$81.28	$ 67.72 - $109.20
2013	240,000	$82.00	$82.00

As of December 31, 2008, Legacy had the following NYMEX West Texas Intermediate crude oil collar contracts that combine a put option or floor with a call option or ceiling as indicated below:

Calendar Year	Volumes (Bbls)	Average Floor	Average Ceiling
2009	75,400	$120.00	$156.30
2010	71,800	$120.00	$156.30
2011	68,300	$120.00	$156.30
2012	65,100	$120.00	$156.30

As of December 31, 2008, Legacy had the following NYMEX Henry Hub, ANR-OK and Waha natural gas swaps paying floating natural gas prices and receiving fixed prices for a portion of its future natural gas production as indicated below:

Calendar Year	Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
2009	3,167,142	$8.06	$ 6.85 - $10.18
2010	2,840,859	$7.87	$ 6.85 - $ 9.73
2011	2,127,316	$8.01	$ 6.85 - $8.70
2012	1,579,736	$8.02	$ 6.85 - $8.70

As of December 31, 2008, Legacy had the following gas basis swaps in which we receive floating NYMEX prices less a fixed basis differential and pay prices on the floating Waha index, a natural gas hub in West Texas. The prices that we receive for our natural gas sales in the Permian Basin follow Waha more closely than NYMEX:

Calendar Year	Annual Volumes (MMBtu)	Basis Differential per Mcf
2009	1,320,000	$(0.68)
2010	1,200,000	$(0.57)

As of December 31, 2008, Legacy had the following gas basis swaps in which we receive floating NYMEX prices less a fixed basis differential and pay prices on the floating ANR-Oklahoma index, a natural gas hub in Oklahoma. The prices we receive for our natural gas sales in the Texas Panhandle and Oklahoma follow ANR-Oklahoma more closely than NYMEX:

Calendar Year	Annual Volumes (MMBtu)	Basis Differential per Mcf
2009	480,000	$(1.09)
2010	480,000	$(0.87)

As of December 31, 2008, Legacy had the following Mont Belvieu, Non-Tet OPIS natural gas liquids swaps paying floating natural gas liquids prices and receiving fixed prices for a portion of its future natural gas liquids production as indicated below:

Calendar Year	Volumes (Gal)	Average Price per Gal	Price Range per Gal
2009	2,265,480	$1.15	$1.15

Interest rate derivatives

On August 29, 2007, Legacy entered into LIBOR interest rate swaps beginning in October of 2007 and extending through November 2011. The swap transaction has Legacy paying its counterparty fixed rates ranging from 4.8075% to 4.82%, per annum, and receiving floating rates on a total notional amount of $54 million. The swaps are settled on a quarterly basis, beginning in January of 2008 and ending in November of 2011.

On March 14, 2008, Legacy entered into a LIBOR interest rate swap beginning in April of 2008 and extending through April of 2011. The swap transaction has Legacy paying its counterparty a fixed rate of 2.68% per annum, and receiving floating rates on a notional amount of $60 million. The swap is settled on a quarterly basis, beginning in July of 2008 and ending in April of 2011.

On October 6, 2008, Legacy entered into two LIBOR interest rate swaps beginning in October of 2008 and extending through October 2011. The swap transactions have Legacy paying its counterparties fixed rates ranging from 3.18% to 3.19%, per annum, and receiving floating rates on a total notional amount of $100 million. The swaps are settled on a quarterly basis, beginning in January of 2009 and ending in October of 2011.

On December 16, 2008, Legacy entered into a LIBOR interest rate swap beginning in December of 2008 and extending through December 2013. The swap transaction has Legacy paying its counterparty a fixed rate of 2.295%, per annum, and receiving floating rates on a total notional amount of $50 million. The swap is settled on a quarterly basis, beginning in March of 2009 and ending in December of 2013.

As the term of Legacys interest rate swaps extend through December of 2013, a period that extends beyond the term of the Legacy Facility which expires on March 15, 2010, Legacy did not designate these derivatives as cash flow hedges, even though they reduce its exposure to changes in interest rates. Therefore, the mark-to-market of these instruments, which amounts to $9.0 million in 2008, is recorded in current earnings and classified as interest expense. The table below summarizes the interest rate swap liabilities as of December 31, 2008.

Notional Amount	Fixed Rate	Effective Date	Maturity Date	Estimated Fair Market Value at December 31, 2008
		(Dollars in thousands)		
$29,000	4.8200%	10/16/2007	10/16/2011	$ (2,480)
$13,000	4.8100%	11/16/2007	11/16/2011	(1,168)
$12,000	4.8075%	11/28/2007	11/28/2011	(1,073)
$60,000	2.6800%	4/1/2008	4/1/2011	(1,540)
$50,000	3.1800%	10/10/2008	10/10/2011	(1,857)
$50,000	3.1900%	10/10/2008	10/10/2011	(1,872)
$50,000	2.2950%	12/18/2008	12/18/2013	(469)
Total Fair Market Value				$ (10,459)

(10) Sales to Major Customers

Legacy operates as one business segment within the Permian Basin region. It sold oil, NGL and natural gas production representing 10% or more of total revenues for the years ended December 31, 2008, 2007 and 2006 as shown below:

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

In the exploration, development and production business, production is normally sold to relatively few customers. Substantially all of the Legacys customers are concentrated in the oil and natural gas industry and revenue can be materially affected by current economic conditions, the price of certain commodities such as crude oil and natural gas and the availability of alternate purchasers. Legacy believes that the loss of any of its major purchasers would not have a long-term material adverse effect on its operations.

(11) Asset Retirement Obligation

In June 2001, the FASB issued FAS No. 143, which requires that an asset retirement obligation (ARO) associated with the retirement of a tangible long-lived asset be recognized as a liability in the period in which it is incurred and becomes determinable. Under this method, when liabilities for dismantlement and abandonment costs, excluding salvage values, are initially recorded, the carrying amount of the related oil and natural gas properties is increased. The fair value of the ARO asset and liability is measured using expected future cash outflows discounted at Legacys credit-adjusted risk-free interest rate. Accretion of the liability is recognized each period using the interest method of allocation, and the capitalized cost is depleted using the units of production

method. Should either the estimated life or the estimated abandonment costs of a property change materially upon Legacys quarterly review, a new calculation is performed using the same methodology of taking the abandonment cost and inflating it forward to its abandonment date and then discounting it back to the present using Legacy's credit-adjusted-risk-free rate. The carrying value of the asset retirement obligation is adjusted to the newly calculated value, with a corresponding offsetting adjustment to the asset retirement cost.

The following table reflects the changes in the ARO during the years ended December 31, 2008, 2007, and 2006.

	December 31,		
	2008	2007	2006
	(In thousands)		
Asset retirement obligation beginning of period	$ 15,920	$ 6,493	$ 2,302
Liabilities incurred in Legacy formation			1,467
Liabilities incurred with properties acquired	25,023	3,033	1,889
Liabilities incurred with properties drilled	456	114	23
Liabilities settled during the period	(440)	(372)	(213)
Liabilities associated with properties sold	(304)		242
Current period accretion	1,396	470	
Current period revisions to previous estimates	38,373	6,182	783
Asset retirement obligation end of period	$ 80,424	$ 15,920	$ 6,493

The discount rate used in calculating the ARO was 3.625% at December 31, 2008, 6.47% at December 31, 2007 and 7.25% at December 31, 2006. These rates approximate Legacys borrowing rates.

Each year the Partnership reviews and, to the extent necessary, revises its asset retirement obligation estimates. During 2008, Legacy obtained new quotes and conducted a new study to evaluate the cost of decommissioning its properties. As a result, Legacy increased its estimates of future asset retirement obligations by $38.4 million to reflect recent costs incurred for plugging and abandonment activities in the Permian Basin of West Texas and southeast New Mexico, where substantially all of its wells and production platforms are located.

(12) Earnings (Loss) Per Unit

The following table sets forth the computation of basic and diluted net earnings (loss) per unit (dollars in thousands, except per unit):

	December 31,		
	2008	2007	2006

		(In thousands)	
Income (loss) available to unitholders	$ 158,207	$ (55,662)	$ 4,357
Weighted average number of units outstanding	30,596	26,155	16,567
Effect of dilutive securities:			
Restricted units	20		2
Weighted average units and potential units outstanding	30,616	26,155	16,569
Basic and diluted earnings (loss) per unit	$ 5.17	$ (2.13)	$ 0.26

At December 31, 2007, 45,078 restricted units were outstanding, but were not included in the computation of diluted earnings per share due to their anti-dilutive effect.

(13) Unit-Based Compensation

Long Term Incentive Plan

Concurrent with the Formation Transaction on March 15, 2006, a Long-Term Incentive Plan (LTIP) for Legacy was created and Legacy adopted SFAS No. 123(R), *Share-Based Payment*. Legacy adopted the Legacy Reserves LP Long-Term Incentive Plan for its employees, consultants and directors, its affiliates and its general partner. The awards under the long-term incentive plan may include unit grants, restricted units, phantom units, unit options and unit appreciation rights. The long-term incentive plan permits the grant of awards covering an aggregate of 2,000,000 units. As of December 31, 2008 grants of awards net of forfeitures covering 736,916 units have been made, comprised of 620,050 unit options and unit appreciation rights awards, 65,116 restricted unit awards and 51,750 phantom unit awards. The LTIP is administered by the compensation committee of the board of directors of its general partner.

SFAS No. 123(R) requires companies to measure the cost of employee services in exchange for an award of equity instruments based on a grant-date fair value of the award (with limited exceptions), and that cost must generally be recognized over the vesting period of the award. Prior to April of 2007, Legacy utilized the equity method of accounting as described in SFAS No. 123(R) to recognize the cost associated with unit options. However, SFAS No. 123(R) stipulates that if an entity that nominally has the choice of settling awards by issuing stock predominately settles in cash, or if entity usually settles in cash whenever an employee asks for cash settlement, the entity is settling a substantive liability rather than repurchasing an equity instrument.

The initial vesting of options occurred on March 15, 2007, with initial option exercises occurring in April 2007. At the time of the initial exercise Legacy settled these exercises in cash and determined it was likely to do so for future option exercises. Consequently, in April 2007, Legacy began accounting for unit option grants by utilizing the liability method as described in SFAS No. 123(R). The liability method requires companies to measure the cost of the employee services in exchange for a cash award based on the fair value of the underlying security at the end of the period. Compensation cost is recognized based on the change in the liability between periods.

Unit Options and Unit Appreciation Rights

During the year ended December 31, 2006, Legacy issued 273,000 unit option awards to officers and employees which vest ratably over a three-year period. During the year ended December 31, 2007, Legacy issued 32,000 unit option awards and 81,000 unit appreciation rights (UARs) to employees which vest ratably over a three-year period. During the year ended December 31, 2007, Legacy issued 66,116 UARs to employees which cliff-vest at the end of a three-year period. During the year ended December 31, 2008, Legacy issued 104,000

UARs to employees which vest ratably over a three-year period. During the year ended December 31, 2008, Legacy issued 108,450 UARs to employees which cliff-vest at the end of a three-year period. All options and UARs granted in 2006, 2007 and 2008 expire five years from the grant date and are exercisable when they vest.

For the years ended December 31, 2008 and 2007, Legacy recorded income of $2,409 and compensation expense of $826,406, respectively, due to the changes in the compensation liability related to the above awards based on its use of the Black Scholes model to estimate the December 31, 2008 and 2007 fair value of these unit option awards and the exercise date fair value of options exercised during the period. As of December 31, 2008, there was a total of $207,245 of unrecognized compensation costs related to the un-exercised and non-vested portion of these unit option awards and UARs. At December 31, 2008, this cost was expected to be recognized over a weighted-average period of 1.7 years. Compensation expense is based upon the fair value as of December 31, 2008 and is recognized as a percentage of the service period satisfied. Since Legacy’s trading history does not yet match the term of the outstanding unit option and UAR awards, it has used an estimated volatility factor of approximately 84% based upon a representative group of publicly-traded companies in the energy industry and employed the fair value method to estimate the December 31, 2008 fair value to be realized as compensation cost based on the percentage of the service period satisfied. In the absence of historical data, Legacy has assumed an estimated forfeiture rate of 5%. As required by SFAS No. 123(R), the Partnership will adjust the estimated forfeiture rate based upon actual experience. Legacy has assumed an annual distribution rate of $2.08 per unit.

A summary of option and UAR activity for the year ended December 31, 2008, 2007 and 2006 is as follows:

	Units	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2006	—	$ —		
Granted	273,000	$ 17.01		
Exercised	—	$ —		$ —
Forfeited	(13,000)	$ 17.00		
Outstanding at December 31, 2006	260,000	$ 17.01	4.2 years	
Options and UARs exercisable at December 31, 2006	—	$ —	—	
Outstanding at January 1, 2007	260,000	$ 17.01		
Granted	179,116	$ 23.09		
Exercised	(23,038)	$ 17.00		$ 228,661
Forfeited	(16,656)	$ 17.09		
Outstanding at December 31, 2007	399,422	$ 19.73	3.6 years	$ 895,048
Options and UARs exercisable at December 31, 2007	62,800	$ 17.04	3.3 years	$ 229,855
Outstanding at January 1, 2008	399,422	$ 19.73		
Granted	212,450	$ 20.31		
Exercised	(5,330)	$ 17.00		$ 34,313
Forfeited	(14,860)	$ 19.44		
Outstanding at December 31, 2008	591,682	$ 19.97	3.5 years	$ 1,900(a)
Options and UARs exercisable at December 31, 2008	169,962	$ 18.76	2.3 years	$ —(b)

(a) At December 31, 2008, the market value of the Partnership's units was $9.31, a price which was less than the average exercise price of outstanding options and UARs of $19.97. At December 31, 2008, there were 2,000 units with an intrinsic value of $0.95 per unit.

(b) At December 31, 2008, there were no exercisable options or UARs with an intrinsic value due to the market value of the Partnership's units of $9.31, a price which is less than the average exercise price of $18.76 per unit for exercisable options and UARs.

The following table summarizes the status of the Partnership's non-vested stock options since January 1, 2008:

	Non-Vested Options and UARs	
	Number of Units	Weighted-Average Fair Value
Non-vested at January 1, 2008	336,622	$ 4.09
Granted	212,450	0.58
Vested — Unexercised	(107,162)	2.61
Vested — Exercised	(5,330)	6.44
Forfeited	(14,860)	3.40
Non-vested at December 31, 2008	421,720	$ 1.75

Legacy has used a weighted-average risk free interest rate of 1.4% in its Black Scholes calculation of fair value, which approximates the U.S. Treasury interest rates at December 31, 2008. Expected life represents the period of time that options are expected to be outstanding and is based on the Partnership's best estimate. The following table represents the weighted average assumptions used for the Black-Scholes option-pricing model:

	Year Ended December 31,		
	2008	2007	2006
Expected life (years)	5	5	6
Annual interest rate	1.4%	3.5%	4.9%
Annual distribution rate per unit	$ 2.08	$ 1.80	$ 1.64
Volatility	84%	41%	37%

Restricted and Phantom Units

As described below, Legacy has also issued phantom units under the LTIP. Because Legacy's current intent is to settle these awards in cash, Legacy is accounting for the phantom units by utilizing the liability method.

On June 27, 2007, Legacy granted 3,000 phantom units to an employee which vest ratably over a five year period, beginning at the date of grant. On July 16, 2007, Legacy granted 5,000 phantom units to an employee which vest ratably over a five year period, beginning at the date of grant. On December 3, 2007, Legacy granted 10,000 phantom units to an employee. The phantom units awarded vest ratably over a three year period, beginning on the date of grant. On February 4, 2008, Legacy granted 2,750 phantom units to four employees which vest ratably over a three-year period, beginning at the date of grant. On May 1, 2008, Legacy granted 3,000 phantom units to an employee which vest ratably over a three-year period, beginning at the date of grant.

In conjunction with these grants, the employees are entitled to dividend equivalent rights (DERs) for unvested units held at the date of dividend payment. Compensation expense related to the phantom units and associated DERs was $130,121 and $52,273 for the years ended December 31, 2008 and 2007, respectively.

On August 20, 2007, the board of directors of Legacys general partner, upon recommendation from the Compensation Committee, approved phantom unit awards which may award up to 175,000 units to five key executives of Legacy based on achievement of targeted annual MLP distribution levels over a base amount of $1.64 per unit. These awards are to be determined annually based solely on the annualized level of per unit distributions for the fourth quarter of each calendar year and subsequently vested over a 3 year period. There is a range of 0% to 100% of the distribution levels at which the performance condition may be met. For each quarter, management recommends to the board an appropriate level of per unit distribution based on available cash of Legacy. This level of distribution is approved by the board subsequent to managements recommendation. Probable issuances for the purposes of calculating compensation expense associated therewith are determined based on managements determination of probable future distribution levels for interim periods and based on actual distributions for annual periods as described above. Expense associated with vesting is recognized over the period from the date vesting becomes probable to the end of the three year vesting period beginning at each year end. On February 4, 2008 the Compensation Committee approved the award of 28,000 phantom units to Legacys five executive officers. In conjunction with these grants, the executive officers are entitled to DERs for unvested units held at the date of dividend payment. Compensation expense related to the phantom units was $346,104 and $44,381 for the years ended December 31, 2008 and 2007, respectively.

On March 15, 2006, Legacy issued 52,616 units of restricted unit awards to two employees. The restricted units awarded vest ratably over a three-year period, beginning on the date of grant. On May 5, 2006, Legacy issued 12,500 units of restricted unit awards to an employee. The restricted units awarded vest ratably over a five-year period, beginning on the date of grant. Compensation expense related to restricted units was $340,656, $340,656 and $270,039 for the years ended December 31, 2008, 2007 and 2006, respectively. As of December 31,

2008, there was a total of $155,618 of unrecognized compensation costs related to the non-vested portion of these restricted units. At December 31, 2008, this cost was expected to be recognized over a weighted-average period of 1.4 years.

On May 1, 2006, Legacy granted and issued 1,750 units to each of its five non-employee directors as part of their annual compensation for serving on Legacys board. The value of each unit was $17.00 at the time of grant. On November 26, 2007, Legacy granted and issued 1,750 units to each of its four non-employee directors as part of their annual compensation for serving on Legacys board. The value of each unit was $21.32 at the time of grant. On March 5, 2008, Legacy issued 583 units, granted on January 23, 2008, to its newly elected non-employee director as part of his pro-rata annual compensation for serving on Legacys board. The value of each unit was $21.20 at the time of grant. On August 29, 2008, Legacy issued 2,500 units, granted on August 26, 2008, to each of its five non-employee directors as part of their annual compensation for serving on the board of directors of Legacys general partner. The value of each unit was $20.09 at the time of issuance.

(14) Costs Incurred in Oil and Natural Gas Property Acquisition and Development Activities

Costs incurred by Legacy in oil and natural gas property acquisition and development are presented below:

	Year Ended December 31,		
	2008	2007	2006
	(In thousands)		
Development costs	$ 71,618	$ 22,967	$ 17,325
Acquisition costs:			
Proved properties	242,127	200,400	187,007

Unproved properties	—	—	—
Total acquisition, development and exploration costs	$ 313,745	$ 223,367	$ 204,332

Property acquisition costs include costs incurred to purchase, lease, or otherwise acquire a property. Development costs include costs incurred to gain access to and prepare development well locations for drilling, to drill and equip development wells, and to provide facilities to extract, treat, and gather natural gas.

(15) Net Proved Oil and Natural Gas Reserves (Unaudited)

The proved oil and natural gas reserves of Legacy have been estimated by an independent petroleum engineer, LaRoche Petroleum Consultants, Ltd., as of December 31, 2008, 2007 and 2006. These reserve estimates have been prepared in compliance with the Securities and Exchange Commission rules based on year-end prices and costs. The table below includes the reserves associated with the Legacy Formation acquisition in March 2006, the Farmer Field and South Justis acquisitions in June 2006 and the Kinder Morgan acquisition in July 2006 which are reflected in the December 31, 2006 balances, the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC and Summit acquisitions which are reflected in the December 31, 2007 balances and the COP III and Pantwist acquisitions which are reflected in the December 31, 2008 balances. An analysis of the change in estimated quantities of oil and natural gas reserves, all of which are located within the United States, is shown below:

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)
Total Proved Reserves:			
Balance, December 31, 2005(a)	8,118	—	24,457
Purchases of minerals-in-place	6,352	—	11,871
Extensions and discoveries	75	—	207
Revisions of previous estimates due to infill drilling, recompletions and stimulations	233	—	494
Revisions of previous estimates due to prices and performance	(657)	—	(2,296)
Production	(749)	—	(2,200)
Balance, December 31, 2006	13,372	—	32,533
Purchases of minerals-in-place	6,367	3,971	19,417
Sales of minerals-in-place	(1)	—	(2)
Revisions from drilling and recompletions	220	—	386
Revisions of previous estimates due to prices and performance	810	180	1,578
Production	(1,179)	(126)	(3,052)
Balance, December 31, 2007	19,589	4,025	50,860
Purchases of minerals-in-place	4,337	1,342	17,665
Sales of minerals-in-place	(241)	—	(112)
Revisions from drilling and recompletions	265	(16)	615
Revisions of previous estimates due to price	(5,658)	(1,322)	(6,666)
Revisions of previous estimates due to performance	(13)	586	1,758

Production	(1,660)	(309)	(4,838)
Balance, December 31, 2008	16,619	4,306	59,282
Proved Developed Reserves:			
December 31, 2005	6,380		20,618
December 31, 2006	11,132		28,126
December 31, 2007	17,434	3,954	45,455
December 31, 2008	14,682	4,254	54,354

(a) Includes 3.2 MMBls of oil and 13.0 Bcf of natural gas held by MBN Properties, LP of which 1.7 MMBls and 7.0 Bcf of natural gas was owned by the non-controlling interest.

(16) Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Reserves (Unaudited)

Summarized in the following table is information for Legacy inclusive of the Legacy Formation acquisition properties from March 2006, the Farmer Field and South Justis acquisition properties from June 2006 and the Kinder Morgan acquisition properties from July 2006, the Binger, Ameristate, TSF, Raven Shenandoah, Raven OBO, TOC and Summit acquisition properties in 2007 and the COP III and Pantwist acquisitions in 2008 with respect to the standardized measure of discounted future net cash flows relating to proved reserves. Future cash inflows are computed by applying year-end prices relating to the Legacys proved reserves to the year-end quantities of those reserves. Future production, development, site restoration, and abandonment costs are derived based on current costs assuming continuation of existing economic conditions. Future net cash flows have not been adjusted for commodity derivative contracts outstanding at the end of each year. Federal income taxes have not been deducted from future production revenues in the calculation of standardized measure as each partner is separately taxed on their share of Legacys taxable income. In addition, Texas margin taxes and the federal income taxes associated with a corporate subsidiary, as discussed in Note 1(f), 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.

	December 31,		
	2008	**2007**	**2006**
		(In thousands)	
Future production revenues	$ 1,137,239	$ 2,431,492	$ 947,914
Future costs:			
Production	(593,756)	(925,450)	(387,238)
Development	(78,457)	(68,745)	(43,419)
Future net cash flows before income taxes	465,026	1,437,297	517,257
10% annual discount for estimated timing of cash flows	(230,011)	(746,759)	(276,694)
Standardized measure of discounted net cash flows	$ 235,015	$ 690,538	$ 240,563

The Standardized Measure is based on the following oil and natural gas prices realized over the life of the properties at the wellhead as of the following dates:

	December 31,		
	2008	**2007**	**2006**

Oil (per Bbl)(a)	$ 41.00	$ 92.50	$ 57.75
Natural Gas (per MMBtu)(b)	$ 5.71	$ 6.80	$ 5.64

(a) The quoted oil price is the West Texas Intermediate physical spot price as of December 31 of the applicable year. This price correlates to a NYMEX near month futures price of $44.60 per Bbl, $95.98 per Bbl and $61.05 per Bbl for December 31, 2008, 2007 and 2006, respectively.

(b) The quoted gas price is the Henry Hub physical spot price as of December 31 of the applicable year. This price correlates to a NYMEX near month futures price of $5.62 per MMBtu, $7.48 per MMBtu and $6.30 per MMBtu for December 31, 2008, 2007 and 2006, respectively

LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table summarizes the principal sources of change in the standardized measure of discounted future estimated net cash flows:

	Year ended December 31,		
	2008	**2007**	**2006**
		(In thousands)	
Increase (decrease):			
Sales, net of production costs	$ (150,707)	$ (77,260)	$ (40,113)
Net change in sales prices, net of production costs	(456,158)	178,972	(60,531)
Changes in estimated future development costs	15,096	1,426	4,582
Extensions and discoveries, net of future production and development costs	—	—	2,723
Revisions of previous estimates due to infill drilling, recompletions and stimulations	1,261	7,347	7,919
Revisions of previous quantity estimates due to performance	1,117	4,273	(12,232)
Previously estimated development costs incurred	7,469	7,345	9,517
Purchases of minerals-in place	72,327	300,907	127,009
Ownership interest corrections	(2,429)	1,480	—
Sales of minerals in place	(6,069)	(22)	—
Other	(3,595)	2,093	(2,971)
Accretion of discount	66,165	23,414	12,663
Net increase (decrease)	(455,523)	449,975	48,566
Standardized measure of discounted future net cash flows:			
Beginning of year	690,538	240,563	191,997
End of year	$ 235,015	$ 690,538	$ 240,563

The data presented should not be viewed as representing the expected cash flow from or current value of, existing proved reserves since the computations are based on a large number of estimates and arbitrary assumptions. Reserve quantities cannot be measured with precision and their estimation requires many judgmental determinations and frequent revisions. Actual future prices and costs are likely to be substantially different from the current prices and costs utilized in the computation of reported amounts.

(17) Selected Quarterly Financial Data (Unaudited)

For the three-month periods ended:

2008	March 31	June 30	September 30	December 31
	(In thousands, except per unit data)			
Revenues:				
Oil sales	$ 36,049	$ 48,439	$ 47,912	$ 25,573
Natural gas liquids sales	3,502	4,781	5,031	2,548
Natural gas sales	9,236	13,389	12,668	6,296
Total revenues	48,787	66,609	65,611	34,417
Expenses:				
Oil and natural gas production	9,528	13,515	15,784	13,177
Production and other taxes	2,469	4,089	4,096	2,058
General and administrative	3,018	3,696	2,158	2,524
Depletion, depreciation, amortization and accretion	9,617	10,523	13,082	30,102(a)
Impairment of long-lived assets	104	4	339	76,495(a)
Loss on disposal of assets	48	26	317	211
Total expenses	24,784	31,853	35,776	124,567
Operating income (loss)	24,003	34,756	29,835	(90,150)
Interest income	55	15	11	12
Interest expense	(4,178)	1,212	(4,198)	(13,989)(b)
Equity in income (loss) of partnership	42	45	47	(26)
Realized and unrealized gain (loss) on oil, NGL and natural gas swaps and oil collar	(40,793)	(216,468)	202,388	231,816
Other	(16)	(3)	(9)	144
Net income (loss) before income taxes	(20,887)	(180,443)	228,074	127,807
Income taxes	(210)	(297)	(122)	581(c)
Income (loss) from continuing operations	(21,097)	(180,740)	227,952	128,388
Gain (loss) on sale of discontinued operation		4,954		(1,250)(d)
Net income (loss)	$ (21,097)	$ (175,786)	$ 227,952	$ 127,138
Income (loss) from continuing operations per unit basic and diluted	$ (0.71)	$ (5.90)	$ 7.34	$ 4.13
Gain (loss) on discontinued operation per unit basic and diluted	$	$ 0.16	$	$ (0.04)
Net income (loss) per unit basic and diluted	$ (0.71)	$ (5.74)	$ 7.34	$ 4.09
Production volumes:				
Oil (MBbl)	379	396	416	469
Natural Gas Liquids (Mgal)	2,721	2,821	3,301	4,134
Natural Gas (MMcf)	1,058	1,238	1,222	1,320
Total (Mboe)	620	670	698	787

(a) The decline in oil and natural gas prices experienced during the fourth quarter of 2008 resulted in a depletion rate and impairment charges significantly higher than those incurred in prior periods of 2008.

(b) The fourth quarter 2008 amount includes mark-to-market expense of $9.4 million related to the interest rate swap derivatives in place as of December 31, 2008.

(c) The fourth quarter income tax amount reflects the adjustment of a portion of the Partnerships deferred tax position from a deferred tax liability to a deferred tax asset as a result of the $76.5 million of impairment incurred during the period.

LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(d) The loss recorded in the fourth quarter of 2008 relates a post close purchase price adjustment related to the Reeves Unit non-monetary exchange with Devon Energy that occurred during the second quarter.

For the three-month periods ended:

2007	**March 31**	**June 30**	**September 30**	**December 31**
	(In thousands, except per unit data)			
Revenues:				
Oil sales	$ 12,301	$ 16,653	$ 22,442	$ 31,905
Natural gas liquids sales	$ 105	$ 1,072	$ 1,714	$ 4,611
Natural gas sales	3,526	5,010	5,241	7,656
Total revenues	15,932	22,735	29,397	44,172
Expenses:				
Oil and natural gas production	4,739	6,088	7,581	8,721
Production and other taxes	994	1,481	1,886	3,528
General and administrative	1,827	2,769	1,443	2,353
Depletion, depreciation, amortization and accretion	5,295	6,811	6,960	9,349
Impairment of long-lived assets	90	190	950	1,974
Loss on disposal of assets		231	156	140
Total expenses	12,945	17,570	18,976	26,065
Operating Income	2,987	5,165	10,421	18,107
Interest income	104	47	54	116
Interest expense	(625)	(893)	(1,905)	(3,695)
Equity in income of partnership		11	30	36
Realized and unrealized gain (loss) on oil, NGL and natural gas swaps	(7,223)	(6,493)	(6,436)	(65,004)
Other		1		(130)
Net income (loss) before income taxes	$ (4,757)	$ (2,162)	$ 2,164	$ (50,570)
Income taxes				(337)
Net income (loss)	$ (4,757)	$ (2,162)	$ 2,164	$ (50,907)
Net income (loss) per unit basic and diluted	$ (0.19)	$ (0.08)	$ 0.08	$ (1.81)
Production volumes:				
Oil (MBbl)	228	273	312	365
Natural Gas Liquids (Mgal)	104	856	1,345	2,991

Natural Gas (MMcf)	588	718	801	945
Total (Mboe)	329	413	478	594

(18) Subsequent Events

On January 20, 2009, the board of directors of Legacy's general partner declared a $0.52 per unit cash distribution for the quarter ended December 31, 2008 to all unitholders of record on February 2, 2009. This distribution was paid on February 13, 2009.