LEGACY RESERVES L P
Form 10-K
March 29, 2007

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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, 2006
	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	**16-1751069**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
303 N. Wall Street, Suite 1600 Midland, Texas	**79701**
(Address of principal executive offices)	*(Zip Code)*

Registrant s telephone number, including area code:
(432) 682-2516

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 Exchange 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 o   No þ

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

Large Accelerated Filer o   Accelerated Filer o   Non-Accelerated Filer þ

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 was approximately $321,202,306 based on the last sales price quoted as of March 26, 2007.

25,455,349 units representing limited partner interests in the registrant were outstanding as of March 26, 2007.

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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 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.

Exploitation. A drilling or other project which may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

MBbls. One thousand barrels of 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 exceeds 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 PDNP s. Proved oil and natural gas reserves that are developed behind pipe, shut-in or 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 recompletion 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 recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

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

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

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

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

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

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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 a share of production.

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

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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;
- financial strategy;
- drilling locations;
- oil and natural gas reserves;
- technology;
- realized oil and natural gas prices;
- production volumes;
- lease operating expenses, general and administrative costs and finding and development costs;
- future operating results; and
- 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, potential, pursue, target, c 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 we cannot assure any reader that such statements will be realized or the forward-looking events and circumstances will 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 rely on them unduly. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

Contact Info: www.LegacyLP.com

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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 Reserve 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) 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 exploitation of oil and natural gas properties primarily located in the Permian Basin of West Texas and southeast New Mexico. 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 an initial public offering of 6,900,000 units representing limited partner interests at an initial public offering price of $19.00 per unit. Net proceeds to the partnership after underwriting discounts and estimated offering expenses were approximately $120 million, all of which were used to repay all indebtedness outstanding under the partnership s credit facility and for general partnership purposes.

Our primary business objective is to generate stable cash flows allowing us to make cash distributions to our unitholders and to increase quarterly cash distributions per unit over time through a combination of acquisitions of new and exploitation 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 exploitation of proved properties as opposed to higher risk exploration of unproved properties.

Our oil and natural gas production and reserve data as of December 31, 2006 are as follows:

- we had proved reserves of approximately 18.8 MMBoe, of which 71% were oil and 79% were classified as proved developed producing, 5% were proved developed non-producing, and 16% were proved undeveloped;
- our proved reserves had a standardized measure of $240.6 million; and
- our proved reserves to production ratio was approximately 14 years based on the average daily net production of 3,625 Boe/d for the three months ended December 31, 2006.

Our reserves are located primarily in the Permian Basin, one of the largest and most prolific oil and natural gas producing basins in the United States. The Permian Basin extends over 100,000 square miles in West Texas and southeast New Mexico and has produced over 24 billion Bbls of oil since its discovery in 1921. The Permian Basin is characterized by oil and natural gas fields with long production histories and multiple producing formations. Our producing properties in the Permian Basin are mature fields with established decline curves.

Acquisition Activities

From January 1, 1999 through December 31, 2006, we invested approximately $146.0 million in 29 acquisitions, which amount excludes $7.0 million allocated to the purchase of operating rights related to our acquisition of oil and natural gas properties located in the South Justis Field, and excludes the purchase of oil and gas assets in the formation transaction. Based on reserve data prepared at the time of these acquisitions, we added a total of approximately 22.7 MMBoe of proved reserves at a reserve acquisition cost of $6.42 per Boe. These additions include our September 2005 acquisition of approximately 5.6 MMBoe of proved

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reserves, as evaluated by LaRoche Petroleum Consultants, Ltd. as of September 30, 2005, from The Prospective Investment and Trading Company, Ltd. (PITCO) for $63.9 million in cash ($64.3 million, inclusive of asset retirement obligations), representing a proved reserve acquisition cost of $11.49 per Boe. The recent acquisitions discussed below are also included in the reserve acquisition cost calculation, but exclude the portion of the acquisition purchase price allocated to the operating rights related to the South Justis Field acquisition.

Acquisitions in 2006

On June 29, 2006, we acquired certain producing properties and related operating rights in the South Justis Field located in Lea County, New Mexico for a purchase price of $13.4 million cash and 146,415 newly issued units. We acquired a 15% operated working interest in the South Justis Unit, a waterflood installed in 1992 that contains 113 producing wells and 97 water injection wells producing approximately 952 gross (125 net) Boe/d for the six months ended June 30, 2006. As of June 30, 2006, total net proved reserves were approximately 0.69 MMBoe, 65% of which are classified as proved developed producing, 21% are proved developed non-producing and 14% are proved undeveloped. We allocated $8.9 million of the $15.9 million net purchase price to the working interest and reserve acquisition resulting in a proved reserve acquisition cost of $12.88 per Boe, and we allocated the balance of $7.0 million to the related operating rights which entitle us to receive approximately $1.7 million of operating fees annually from third party owners of the properties. We refracture stimulated 5 wells in 2006 and expect to refracture stimulate 33 additional existing wells and infill drill twelve 20-acre locations over the next three years.

Also on June 29, 2006 we closed an acquisition of additional operated leases in the Farmer Field, located in Crockett and Reagan counties of West Texas, from Larron Oil Corporation, for $5.6 million cash. We acquired a 100% operated interest in 50 wells producing 76 net Boe/d and net reserves as of June 30, 2006 of 0.44 MMBoe, all of which are classified as proved developed producing resulting in a proved reserve acquisition cost of $12.73 per Boe. Prior to the Farmer Field acquisition, we operated 111 wells in the Farmer Field.

On July 31, 2006, we closed the acquisition of properties from Kinder Morgan for approximately $17.2 million cash after closing adjustments. The Kinder Morgan properties contain 85 producing wells and 44 water injection wells located in nine fields in Texas and southeast New Mexico which produced approximately 300 Boe/d net as of July 31, 2006. We operate over 90% of the production. As of the June 30, 2006 reserve report relating to the Kinder Morgan acquisition, net proved reserves were 1.46 MMBoe, of which 88% are proved developed producing and 12% are proved undeveloped resulting in a proved reserve acquisition cost of $11.78 per Boe.

Proposed Acquisition of Oklahoma Assets

On March 20, 2007, we entered into a definitive agreement to acquire certain oil and natural gas producing properties located in the East Binger (Marchand) Unit in Caddo County, Oklahoma from Nielson & Associates, Inc. for an aggregate purchase price of $45 million, subject to purchase price adjustments, to be paid $30 million in cash and 611,247 newly-issued units. The acquisition is subject to customary closing conditions and is expected to close in mid-April, 2007.

Exploitation Activities

We have also grown reserves and production each year since 1999 through exploitation activities on our existing and acquired properties. Our exploitation activities include accessing additional productive formations in existing wellbores, formation stimulation, artificial lift equipment enhancement, infill drilling on closer well spacing, secondary (waterflood) and tertiary (CO_2) recovery projects, drilling for deeper formations and completing unconventional and tight formations.

As of December 31, 2006, we have identified 109 gross (69.1 net) proved undeveloped drilling locations, 45 gross (9.6 net) recompletion and refracture stimulation projects and one tertiary (CO_2) recovery expansion project on our properties, over 90% of which we intend to drill and execute over the next four years. Excluding acquisitions, we expect to make capital expenditures of approximately $10.3 million during the year ending December 31, 2007, including drilling 30 gross (12.7 net) development wells, executing 21 gross (4.4 net) recompletions and refracture stimulations and expanding one tertiary (CO_2) recovery project. We currently have rigs operating or committed to drill 100% of our expected development wells for the year ending December 31, 2007.

Hedging Activities

Our strategy includes hedging a majority of our oil and natural gas production over a three to five-year period. We have hedged approximately 75% of our expected oil and natural gas production from total proved reserves for the year ending December 31, 2007. We have also hedged approximately 70% of our expected oil and natural gas production from total proved reserves for 2008 through 2010. All of our hedges are in the form of fixed price swaps with average annual NYMEX prices of at least $61.51 per Bbl of oil and $7.99 per MMBtu of natural gas. In July 2006, we entered into basis swaps to receive floating NYMEX 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 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. We have hedged approximately 100% of our NYMEX natural gas basis differential risk on our NYMEX natural gas swaps for 2007 through 2010.

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 exploitation potential;
- Grow proved reserves and maximize cash flow and production through exploitation activities and operational efficiencies;
- Maintain financial flexibility; and
- Reduce commodity price risk through hedging.

Competitive Strengths

We believe that we are well positioned to successfully execute our business strategy because of the following competitive strengths:

- Proven acquisition and exploitation track record;
- Predictable, long-lived reserve base;
- Diversified operations and operational control over approximately 66% of our current production; and
- Experienced management team with a vested interest in our success.

Marketing and Major Purchasers

For the years ended December 31, 2006, 2005 and 2004, sales of oil to ConocoPhillips accounted for 4%, 10% and 9%, respectively, of our total oil and natural gas sales. For the years ended December 31, 2006, 2005 and 2004, sales of oil to Navajo Crude Oil Marketing, a subsidiary of Holly Corporation, accounted for approximately 12%, 16% and 17%, respectively, of our total oil and natural gas sales. For the years ended December 31, 2006, 2005 and 2004, sales of oil to Plains Marketing, LP, a subsidiary of Plains All American, L.P., accounted for 14%, 18% and 20%, respectively, of our total oil and natural gas sales. Our oil

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sales prices are based on formula pricing and calculated using the appropriate buyer s posted price, plus Platt s P-Plus monthly average, plus 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 delay production and sale of our oil and natural gas in that particular purchaser s 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 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.

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, which can be particularly important in the areas in which we operate. As a result, our competitors may be able to pay more for productive oil and natural gas properties and exploratory prospects 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 prospects 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.

We are also affected by competition for drilling rigs, completion rigs and the availability of related equipment. In the past, the oil and natural gas industry has experienced shortages of drilling and completion rigs, equipment, pipe and personnel, which has delayed development drilling and other exploitation activities and has caused significant increases in the prices for this equipment and personnel. We are unable to predict when, or if, such shortages may occur or how they would affect our exploitation program.

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 effecting the price we receive for natural gas. Seasonal anomalies such as mild winters or hot summers sometimes lessen this fluctuation.

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.

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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 EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of crude oil or natural gas are currently regulated under RCRA s non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration 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 exploitation 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 was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property, or perform remedial 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 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, regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, 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 Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of oil and natural gas projects.

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

Recent studies have suggested that emissions of certain gases may be contributing to warming of the Earth s atmosphere. In response to these studies, many nations have agreed to limit emissions of greenhouse gases pursuant to the United Nations Framework Convention of 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 recently 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. 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, in late 2006, the U.S. Supreme Court will review the U.S. Circuit Court of Appeals for the District of Columbia s ruling in Massachusetts, et al. v. EPA, in which the appellate court held that the U.S. Environmental Protection Agency had discretion under the Clean Air Act to refuse to regulate carbon dioxide emissions from mobile sources. A Supreme Court reversal of the appellate decision could result in federal regulation of carbon dioxide emissions and other greenhouse gases, and may affect the outcome of other climate change lawsuits pending in U.S. federal courts in a manner unfavorable to our industry. 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, 2006. Additionally, as of the date of this document, we are not aware of any environmental issues or claims that require material capital expenditures during 2007. 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 operation.

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 proration 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. Federal and state regulations govern the price and terms for access to natural gas pipeline transportation. The Federal Energy Regulatory Commission s regulations for interstate natural gas transmission in some circumstances may also affect the intrastate transportation of natural gas.

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 allowables from natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that they will not do so in the future. The effect of these regulations may be to limit the amounts of natural gas that may be produced from our wells, and to limit the number of wells or locations we can drill.

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, 2006, we had 23 full-time employees, including seven petroleum engineers, five accountants and two 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 35,000 square feet of office space in Midland, Texas at 303 W. Wall Street, Suite 1600, where our principal offices are located, from TCTB Partners, a limited partnership of which Dale A. Brown, Cary D. Brown and Kyle A. McGraw are limited partners. Please read Certain Relationships and Related Transactions Transactions with Executive Officers, Directors and Principal Unitholders. The lease for our Midland office expires in August 2011.

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 of $0.41 per unit. 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 and natural gas we produce;
- the price at which we are able to sell our oil and natural gas production;
- whether we are able to acquire additional oil and natural gas properties at economically attractive prices;
- whether we are able to continue our exploitation activities at economically attractive costs;
- the level of our operating 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.

If we are unable to develop our proved undeveloped reserves and our wells do not produce as expected, our reserves may decline more rapidly than we have estimated. Our future oil and natural gas reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future

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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.

Because we distribute all of our available cash to our unitholders, our future growth may be limited.

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. We will 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. If we are unable to obtain adequate financing from these sources, our ability to grow will be limited.

If commodity prices decline significantly for a prolonged period, we may be forced to reduce our distribution or not be able to pay distributions at all.

A significant decline in oil and natural gas prices over a prolonged period would have a significant impact on the value of our reserves and on our cash flow, 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. For example, during the year ended December 31, 2006, the NYMEX monthly oil index price ranged from a high of $77.03 per Bbl to a low of $55.81 per Bbl and the NYMEX gas index price (near month contract) ranged from a high of $10.63 per MMbtu to a low of $4.20 per MMBtu.

If commodity prices decline significantly for a prolonged period, a significant portion of our exploitation projects may become uneconomic, which may adversely affect 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, substantial decreases in oil and natural gas prices as were experienced as recently as 2002, when prices of less than $20.00 per Bbl of oil and $2.00 per Mcf of natural gas were received at the wellhead in the Permian Basin, would render a significant portion of our exploitation projects uneconomic. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs, or if our estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties for impairments. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken and our ability to borrow funds under our credit facility to pay distributions to our unitholders.

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 credit facility has substantial restrictions and financial covenants, and our borrowing base is subject to redetermination by our lenders which could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

We will depend on our revolving credit facility for future capital needs. Our revolving credit facility restricts, among other things, our ability to incur debt and pay distributions, and requires 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. 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. Additionally, our revolving credit facility limits the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion.

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 Operations Financing Activities.

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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 exploitation 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 exploitation, 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 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 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 exploitation 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.

Much of our business activities are conducted through joint operating agreements under which we own partial interests in oil and natural gas wells. We currently operate approximately 66% of our production.

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 exploitation activities 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.

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Shortages of drilling rigs, equipment and crews could delay our operations, adversely affect our ability to increase our reserves and production and reduce our cash available for distribution to our unitholders.

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

Increases in the cost of drilling rigs, service rigs, pumping services and other costs in drilling and completing wells could reduce the viability of certain of our exploitation projects.

The rig count and the cost of rigs and oil field services necessary to implement our exploitation projects have risen significantly with the increases in oil and natural gas prices. 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, which have recently experienced record lows, will reduce our cash available for distribution.

The credit markets recently have experienced 50-year record lows in interest rates. If the overall economy strengthens, it is likely that monetary policy will tighten further, resulting in higher interest rates to counter possible inflation. Additionally, interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. Increased interest expense and financing costs will reduce our cash available for distribution.

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. We have identified, as of December 31, 2006, 119 gross (69.1 net) proved undeveloped drilling locations. 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.

Our hedging activities could result in cash losses, could reduce our cash available for distributions and may limit potential gains.

We have entered into, and we may in the future enter into, hedging arrangements for 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. For example, during the year ended December 31, 2006 our average historical unhedged sales price for oil was $60.55 per Bbl and our average historical sales price including the effects of realized hedge settlements was $51.65 per Bbl. For the same period, our average historical unhedged sales price for natural gas was $6.57 per Mcf and our average historical sales price including the effects of realized hedge settlements was $9.48 per Mcf. Net hedge settlement losses were approximately $0.3 million for the year ended December 31, 2006. During the year ended December 31, 2006, 89% of our oil and 79% of our natural gas production was hedged.

If our actual production and sales for any period are less than our hedged production and sales for that period (including reductions in production due to 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 hedging obligations without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity. Lastly, an attendant risk exists in hedging activities that the counterparty in any derivative transaction cannot or will not perform under the instrument and that we will not realize the benefit of the hedge. Under our credit facility, we are prohibited from hedging all of our production, and we therefore retain the risk of a price decrease on our unhedged volumes.

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 hedging arrangements 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 exploitation 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.

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

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. 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 develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002 by our initial compliance date of December 31, 2007. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet 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.

Risks Related to Our Limited Partnership Structure

Our Founding Investors, including members of our management, own a 52% 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 52% limited partner interest in us and control 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.

Unitholders have limited voting rights and are not entitled to elect our general partner on an annual or other continuing basis.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management decisions regarding our business. Unitholders did not elect our general partner or its board of directors, and while our unitholders will annually elect the board of directors of our general partner, they will have no right to elect our general partner on an annual or other continuing basis. As a result of these limitations, the price at which the units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Even if unitholders are dissatisfied they cannot remove our general partner without the consent of unitholders owning at least 662/3% 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 662/3% 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 52% 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. Please read Certain Relationships and Related Transactions, and Director Independence. The reimbursement of expenses of our general partner and its affiliates could adversely affect our ability to pay cash distributions to our unitholders.

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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 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 that constitute 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 entity-level taxation by individual states. If the IRS were to treat us as a corporation for federal income tax purposes or we were to become subject to entity-level taxation for state tax purposes, taxes paid, if any, will reduce our cash available for distribution to our unitholders.

The anticipated after-tax 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 that affects 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 rates, currently at a maximum rate of 35%, and would likely pay state income tax at varying rates. Distributions to our unitholders would generally be taxed as corporate distributions, and no income, gain, loss, deduction or credit would flow through to our unitholders. Because a tax may be imposed on us as a corporation, our cash available for distribution to our unitholders could be reduced. Thus, any treatment of us as a corporation could result in a material reduction in the anticipated cash flow and after-tax return to our unitholders and, therefore, result in a substantial reduction in the value of our units.

Current law or our business may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. For example, we will be subject to a new entity-level state tax on the portion of our income that is generated in Texas beginning for tax reports due on or after January 1, 2008. Specifically, the Texas margin tax will be imposed at a maximum effective rate of 0.7% of our gross income that is apportioned to Texas. 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.

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.

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 a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter that affects us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take and a court may disagree with some or all of those positions. Any contest with the IRS may materially and adversely impact the market for our units and the price at which they trade. In addition, our costs of any contest with the IRS will result in a reduction in cash available for distribution 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 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 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 depreciation and amortization positions that may not conform with all aspects of existing Treasury regulations. 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.

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 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 foreign, state and local income tax returns and pay state and local income taxes in some or all of these 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 and Mississippi. 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, foreign, 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 the 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 for 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. A constructive termination results in the closing of our taxable year for all unitholders and in the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, may result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. A constructive termination occurring on a date other than December 31 will result in us filing two tax returns (and unitholders receiving two Schedule K-1s) for one fiscal year and the cost of the preparation of these returns will be borne by all unitholders.

ITEM 1B. *UNRESOLVED STAFF COMMENTS*

None.

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ITEM 2. *PROPERTIES*

As of December 31, 2006 we owned interests in producing oil and natural gas properties in 146 fields in the Permian Basin, operated 744 gross productive wells and owned non-operated interests in 1,207 gross productive wells. The following table sets forth information about our proved oil and natural gas reserves as of December 31, 2006. 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.

	As of December 31, 2006					
	Proved Reserves			Standardized Measure		
Field	**MMBoe**	**R/P(a)**	**% Oil**		**Amount ($ in Millions)**	**% of Total**
Denton	1.8	11	86%	$	22.2	9.2%
Farmer	2.0	18	66		20.1	8.4
Spraberry	1.6	16	70		19.9	8.3
Hobbs	1.1	17	88		15.3	6.4
Lea	1.2	17	70		14.4	6.0
Howard Glasscock/Iatan/Iatan East	1.1	15	99		13.7	5.7
Langlie Mattix	1.2	30	92		13.2	5.5
Total Top 7 fields	10.0	16	80%	$	118.8	49.5%
All others	8.8	13	61		121.8	50.5
Total	18.8	14	71%	$	240.6	100.0%

(a) Reserves as of December 31, 2006 divided by production volumes for the year ended December 31, 2006.

Summary of Oil and Natural Gas Properties and Projects

Our most significant fields are the Denton, Farmer, Spraberry, Langlie Mattix, Howard Glasscock/Iatan/Iatan East Howard, Hobbs and Lea fields. As of December 31, 2006 these seven fields accounted for approximately 53.1% of our total estimated proved reserves.

Denton Field. The Denton field is an oil and natural gas field located in Lea County, New Mexico. This field was discovered in 1950 and through December 31, 2006, our properties in this field have gross cumulative production of 52.3 MMBbls of oil and 29.4 Bcf of natural gas. 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 12 producing wells with a 15.0% average non-operated working interest. As of December 31, 2006, our properties in the Denton field contained 1.8 MMBoe (86% oil) of net proved reserves with a standardized measure of $22.2 million. The average net daily production from this field was 462 Boe/d for the fourth quarter of 2006. The estimated reserve life (R/P) for the field is 11 years.

The Denton field has a natural water drive and most of the wells produce large amounts of water utilizing high volume lift submersible pumps. We have one proved developed non-producing, or PDNP, project identified in the Devonian formation of this field and three unclassified high volume lift candidates in the Wolfcamp formation of this field.

Farmer Field. The Farmer field is an oil and natural gas field located in Crockett and Reagan County, Texas. This field was discovered in 1953 and through December 31, 2006, our properties in this field have gross cumulative production of 5.6 MMBbls of oil and 12.4 Bcf of natural gas. The San Andres Formation at depths of 2,100 to 2,600 feet is the primary reservoir in the Farmer field. We operate 161 wells (153 producing, 8 injecting including the Farmer Field acquisition) in the Farmer field with a 100.0% average working interest and a net revenue interest ranging from 80.3% to 87.3%. As of December 31, 2006, our properties in the Farmer field contained 2.0 MMBoe (66% oil) of net proved reserves with a standardized measure of $20.1 million. The average net daily production from this field was 309 Boe/d for the fourth quarter of 2006. The estimated reserve life (R/P) for the field is 18 years.

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 33 10-acre proved undeveloped, or PUD, locations in this field and an additional 84 unproved 10-acre locations.

Spraberry Field. The Spraberry field is located in Midland, Martin, Reagan and Upton counties, Texas. This field was discovered in 1949 and through December 31, 2006, our properties in this field have combined gross cumulative production of oil of 2.0 MMBbls and natural gas of 6.7 Bcf. This field produces from Spraberry and Wolfcamp age formations from 5,000 to 10,200 feet. We operate 13 active wells in this field with working interests ranging from 35.0% to 100% and net revenue interests ranging from 28.0% to 82.0%. We have a 1.3% overriding royalty interest in one non-operated unit in the Spraberry field. As of December 31, 2006, our properties in the Spraberry field contained 1.6 MMBoe (70% oil) of net proved reserves with a standardized measure of $19.9 million. The average net daily production from this field was 275 Boe/d for the fourth quarter of 2006. The estimated reserve life for this field is 16 years.

Hobbs Field. The Hobbs field is an oil and natural gas field located in Lea County, New Mexico. The field was discovered in 1928 and through December 31, 2006 our properties in the Hobbs field have a combined gross cumulative production of 352.8 MMBbls of oil and 411.4 Bcf of natural gas. The Grayburg and San Andres formations at depths of 3,850 to 4,300 feet are the primary reservoirs in the Hobbs field. We have a non-operated working interest in two Occidental Permian Ltd. operated properties, the North Hobbs Unit and the South Hobbs Unit. Working interests are 1.3% and 1.1% respectively with net revenue interests of 1.1% and 0.9% respectively. We also operate one well producing from the Drinkard formation with a 100% working interest and 87.5% net revenue interest. There are a total of 430 active wells (262 producing, 168 injecting) on these properties and they contain 1.1 MMBoe (88% oil) of net proved reserves with a standardized measure of $15.3 million. The average net daily production from the Hobbs field was 181 Boe/d for the fourth quarter of 2006. The estimated reserve life (R/P) for these fields is 17 years.

The North Hobbs Unit is currently being CO_2 flooded with ongoing expansion of the enhanced oil recovery project. The South Hobbs Unit is currently being waterflooded and has potential for enhanced oil recovery using CO_2 injection, but has not been evaluated by our engineers or LaRoche Petroleum Consultants, Ltd.

Lea Field. The Lea field is an oil and natural gas field located in Lea County, New Mexico. This field was discovered in 1960 and through December 31, 2006 our properties in this field have gross cumulative production of 10.3 MMBbls of oil and 31.1 Bcf of natural gas. The Devonian Formation at depths of 14,200 to 14,600 feet is the primary reservoir in the Lea field. Additional production has been developed in 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 in the Lea Field with a 68.7% average working interest and a 60.1% average net revenue interest. We also own another two wells with a 10.3% average non-operated working interest. As of December 31, 2006, our properties in the Lea field contained 1.2 MMBoe (70% oil) of net proved reserves with a standardized measure of $14.4 million. The average net daily production from this field was 192 Boe/d for the fourth quarter of 2006. The estimated reserve life (R/P) for the Lea field is 17 years.

We have four proved undeveloped and four unclassified drilling locations in the Bone Spring Formation which are all 40-acre infill wells. There is also significant production from the Delaware formation less than a mile northwest of the Lea field and we are currently evaluating development of the Delaware formation in the Lea field. The Delaware formation is not included in our reserve report.

Howard Glasscock, Iatan and Iatan East Howard Fields. The Howard Glasscock, Iatan and Iatan East Howard fields adjoin one another and are located in Howard and Mitchell counties, Texas. These fields were discovered in 1925 and through December 31, 2006, our properties in these fields have a gross cumulative production of 10.5 MMBbls of oil and 0.6 Bcf of natural gas. These fields produce from multiple formations of Permian age which primarily include the San Andres, Yates, Seven Rivers, Queen, Clearfork and Glorieta Formations from 1,000 to 3,700 feet as well as the Wolfcamp and Canyon Formations from 5,100 to 7,400 feet.

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We operate 137 wells (127 producing, 10 injecting) in these fields with working interests ranging from 62.5% to 100.0% and net revenue interests ranging from 46.8% to 87.5%. As of December 31, 2006, our properties in the Howard Glasscock, Iatan and Iatan East Howard fields contained 1.1 MMBoe (99% oil) of net proved reserves with a standardized measure of $13.7 million. The average net daily production from these fields was 197 Boe/d for the fourth quarter of 2006. The estimated reserve life (R/P) for these fields is 15 years.

Langlie Mattix Field. The Langlie Mattix field is an oil and natural gas field located in Lea County, New Mexico. This field was discovered in the late 1930s and through December 31, 2006, our properties in this field have gross cumulative production of 18.2 MMBbls of oil and 16.4 Bcf of natural gas. The Queen Formation at depths of 3,400 to 3,800 feet is the primary reservoir in the Langlie Mattix field. We operate 99 wells (77 producing, 22 injecting) in the Langlie Mattix Penrose Sand Unit, a subdivision of the Langlie Mattix Field, with a 50.7% average working interest and a 44.1% average net revenue interest. We also operate two other properties with 100% and 82.4% working interests and 82.0% and 67.4% net revenue interests. As of December 31, 2006, our properties in the Langlie Mattix field contained 1.2 MMBoe (92% oil) of net proved reserves with a standardized measure of $13.2 million. The average net daily production from this field was 111 Boe/d for the fourth quarter of 2006. The estimated reserve life (R/P) for the field is 16 years.

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 14 20-acre infill wells drilled on the Unit; five drilled in 1983, three drilled in 1992, and six drilled in 2004. All three 20-acre infill programs were successful. We have 30 20-acre infill proved undeveloped locations and an additional 55 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, 2006		
	2004	**2005(a)**	**2006**
Reserve Data:			
Estimated net proved reserves:			
Oil (MMBbls)	4.1	8.1	13.4
Natural Gas (Bcf)	10.5	24.5	32.5
Total (MMBoe)	5.9	12.2	18.8
Proved developed reserves (MMBoe)	5.9	9.8	15.8
Proved undeveloped reserves (MMBoe)		2.4	3.0
Proved developed reserves as a percentage of total proved reserves	100%	80%	84%
Standardized measure (in millions)(b)	$ 60.4	$ 192.0	$ 240.6
Oil and Natural Gas Prices(c)			
Oil NYMEX WTI per Bbl	$ 43.45	$ 61.05	$ 61.05
Natural gas NYMEX Henry Hub per MMBtu	$ 6.15	$ 11.25	$ 6.30

(a) Includes 3.2 MMBbls of oil, 13.0 Bcf of natural gas and $93.0 million of standardized measure held by MBN Properties LP of which 1.7 MMBbls of oil, 7.0 Bcf of natural gas and $50.2 million of standardized measure was owned by the non-controlling interest.

(b) 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

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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 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 have 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 Management s Discussion and Analysis of Financial Condition and Results of Operations Cash Flow from Operating Activities.

(c) Oil and natural gas prices as of each date are based on NYMEX prices per Bbl of oil and per MMBtu of natural gas at such date, with these representative prices adjusted by field to arrive at the appropriate net price.

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 drilled to known reservoirs 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 to establish production.

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 has 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 2006, we paid LaRoche Petroleum Consultants, Ltd. approximately $246,992 for such reserve and economic evaluations.

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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) as of December 31, 2004, 2005 and 2006. The 2006 data 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:

	Year Ended December 31,		
	2004	**2005(a)**	**2006(b)**
Production:			
Oil (MBbl)	286	354	749
Gas (MMcf)	783	1,027	2,200
Total (MBOE)	416	525	1,116
Average daily production (BOE per day)	1,138	1,438	3,058
Average sales price per unit (including hedges)(c):			
Oil (per Bbl)	$ 36.24	$ 38.94(d)	$ 57.44(e)
Gas (per Mcf)	$ 5.04	$ 5.45	$ 11.85
Combined (per BOE)	$ 34.40	$ 36.92(d)	$ 61.90(e)
Average sales price per unit (including realized hedge gains/losses)(f):			
Oil (per Bbl)	$ 38.61	$ 41.51(d)	$ 51.65(e)
Gas (per Mcf)	$ 4.89	$ 7.13	$ 9.48
Combined (per BOE)	$ 35.74	$ 41.93(d)	$ 53.35(e)
Average sales price per unit (excluding hedges):			
Oil (per Bbl)	$ 38.45	$ 51.48	$ 60.55
Gas (per Mcf)	$ 5.04	$ 7.13	$ 6.57
Combined (per BOE)	$ 35.92	$ 48.65	$ 53.58
Average unit costs per BOE:			
Production costs, excluding production and other taxes	$ 10.44	$ 12.14	$ 14.28
Production and other taxes	$ 2.23	$ 3.12	$ 3.36
General and administrative	$ 1.76	$ 2.58	$ 3.31
Depletion, depreciation and amortization	$ 2.12	$ 4.36	$ 16.48

(a) Reflects the production and operating results of the PITCO properties from their acquisition on September 14, 2005.

(b) 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.

(c) Includes both the realized and unrealized hedge gains and losses from Legacy s oil and natural gas swaps. Since Legacy does not specifically designate its commodity derivative instruments as cash flow hedges, current earnings reflect a mark-to-market adjustment for these instruments. Unrealized gains and losses represent a current period mark-to-market adjustment for commodity derivatives which will be settled in future periods. See Note 9 on page F-23 for details regarding Legacy s unrealized gains and losses.

(d) Includes the effects of approximately $2.0 million of derivative premiums for the year ended December 31, 2005 to cancel and reset 2006 oil swaps from $51.31 to $59.38 per Bbl and approximately $0.8 million of premiums paid on July 22, 2005 for an option to enter into a $55.00 per Bbl oil swap related to the PITCO acquisition that was not exercised.

(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

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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.

(f) Includes only the realized hedge gains (losses) from Legacy s oil and natural gas swaps.

Productive Wells

The following table sets forth information at December 31, 2006 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	695	519.51	49	41.62
Non-operated	1,128	60.34	79	13.97
Total	1,823	579.85	128	55.59

Developed and Undeveloped Acreage

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

	Developed Acreage(a)		Undeveloped Acreage(b)	
	Gross(c)	**Net(d)**	**Gross(c)**	**Net(d)**
Total	183,323	52,013		

(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. 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.

(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.

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Drilling Activity

The following table sets forth information, on a combined basis, with respect to wells completed by the Moriah Group, Brothers Group, H2K, and the charitable foundations, during the years ended December 31, 2004, 2005 and 2006. No information relating to the PITCO properties is included in the total for the year ended December 31, 2004. The drilling activities associated with the PITCO properties are included for all periods subsequent to the acquisition date of September 14, 2005. 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 information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. 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,		
	2004	**2005**	**2006**
Gross:			
Development			
Productive	12	12	14
Dry			2
Total	12	12	16
Exploratory			
Productive	2		
Dry	1	1	
Total	3	1	
Net:			
Development			
Productive	3.0	1.6	6.2
Dry			1.3
Total	3.0	1.6	7.5
Exploratory			
Productive	0.2		
Dry	0.2	0.1	
Total	0.4	0.1	

Summary of Exploitation Projects

We are currently pursuing an active exploitation strategy. We estimate that our capital expenditures for the year ending December 31, 2007 will be approximately $10.3 million for development drilling, recompletions and refracture stimulation and other exploitation related projects to implement this strategy. We intend to drill 30 gross (12.7 net) development wells and execute 21 gross (4.4 net) recompletions and refracture simulations and expand one tertiary (CO_2) recovery project. All of these exploitation projects are located in the Permian Basin.

Operations

General

We operate approximately 66% of our net daily production of oil and natural gas. We design and manage the development, recompletion 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. 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 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 ranges from 12.5% to 25.0% resulting in a 87.5% to 75.0% 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.

Hedging Activity

We enter into hedging 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 hedges in place are NYMEX financial swaps, which do not require option premiums. Our hedges either swap floating prices for fixed prices indexed on NYMEX for both oil and natural gas or swap the NYMEX index price to an index that reflects a geographical area of production, in our case, the Waha natural gas index. We do not have any interest rate swaps in place. For a more detailed discussion of our hedging activities, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Cash Flow from Operations and Quantitative and Qualitative Disclosures About Market Risk.

Title to Properties

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

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property.

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

ITEM 3. *LEGAL PROCEEDINGS*

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

ITEM 4. *SUBMISSION OF MATTERS TO A VOTE OF UNITHOLDERS*

None.

PART II

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

Our units are listed on the NASDAQ Global Market under the symbol LGCY . As of March 26, 2007, there were 25,455,349 units outstanding, held by approximately 11 holders of record, including units held by our Founding Investors.

Our units were first offered and sold to the public on January 12, 2007. The following table sets forth, for the periods indicated, the quarterly cash distributions paid to our unitholders.

2006		**Cash Distribution per Unit**
Period from March 15, 2006 to March 31, 2006	$	0.0774(a)(b)
Second Quarter	$	0.4100(c)
Third Quarter	$	0.4100(c)
Fourth Quarter	$	0.4100(d)

(a) Reflects a pro-rated distribution for the period from March 15, 2006 through March 31, 2006.

(b) We paid total cash distributions to our general partner with respect to its approximately 0.1% general partner interest of $1,417.

(c) We paid total cash distributions to our general partner with respect to its approximately 0.1% general partner interest of $7,508.

(d) The record date of our distribution attributable to the fourth quarter of 2006 was January 10, 2007 per a declaration of Legacy s board on January 3, 2007 and preceded the closing of our initial public offering. Accordingly, unitholders of units issued in our initial public offering were not entitled to receive a distribution attributable to the fourth quarter of 2006 on such units.

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 $0.41 per unit.

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Recent Sales of Unregistered Securities

In October 2005, in connection with the formation of Legacy Reserves LP, we issued to Moriah Resources, Ltd. the 99.9% limited partner interest in Legacy Reserves LP for $999. The issuance was exempt from registration under Section 4(2) of the Securities Act because the transaction did not involve a public offering.

In connection with our formation transactions on March 15, 2006, we issued units to our Founding Investors contributing oil and natural gas properties and related assets to us. The issuances of the units described below was exempt from registration under Section 4(2) of the Securities Act because the issuances did not involve a public offering. The following table summarizes the issuance of our units in the formation transactions:

	Units
Moriah Group	
Moriah Properties, Ltd.	7,334,070
DAB Resources, Ltd.	859,703
Brothers Group	
Brothers Production Properties, Ltd	4,968,945
Brothers Production Company, Inc.	264,306
Brothers Operating Company, Inc.	52,861
J&W McGraw Properties, Ltd.	914,246
MBN Properties LP	3,162,438
H2K Holdings, Ltd.	83,499

On March 15, 2006, we issued an aggregate of 52,616 restricted units to certain members of management pursuant to the Legacy Reserves LP Long-Term Incentive Plan. The issuances of these units were exempt from the registration requirements of the Securities Act pursuant to Rule 701.

On March 15, 2006, we issued 5,000,000 units in a private offering for an aggregate consideration of $85 million before the initial purchaser s discount, placement agent s fees and expenses to qualified institutional investors and accredited investors in transactions exempt from registration under Section 4(2) of the Securities Act. We paid Friedman, Billings, Ramsey & Co., Inc., who acted as placement agent and initial purchaser in this transaction, $5.95 million in initial purchaser s discount and placement agent s fees.

On May 1, 2006, we issued 8,750 units in the aggregate to certain of the directors of our general partner pursuant to the Legacy Reserves LP Long-Term Incentive Plan. The issuances of these units were exempt from the registration requirements of the Securities Act pursuant to Rule 701.

On May 5, 2006, we issued 12,500 restricted units to an employee pursuant to the Legacy Reserves LP Long-Term Incentive Plan. The issuance of these units was exempt from the registration requirements of the Securities Act pursuant to Rule 701.

On June 29, 2006, and November 10, 2006 we issued 138,000 units and 8,415 units, respectively, to Henry Holding LP as partial consideration for our acquisition of oil and natural gas producing properties located in Lea County New Mexico and contract operating rights for total consideration of approximately $13.4 million cash and 146,415 units. The issuances of these units were exempt from registration under Section 4(2) of the Securities Act because the issuances did not involve a public offering.

On July 17, 2006, we issued options to purchase 251,000 units to employees and officers pursuant to the Legacy Reserves LP Long-Term Incentive Plan. The issuance of these options were exempt from the registration requirements of the Securities Act pursuant to Rule 701.

On September 15, 2006, we issued options to purchase 10,000 units to an employee pursuant to the Legacy Reserves LP Long-Term Incentive Plan. The issuance of these options was exempt from the registration requirements of the Securities Act pursuant to Rule 701.

On October 10, 2006 we issued options to purchase 12,000 units to employees pursuant to the Legacy Reserves LP Long-Term Incentive Plan. The issuance of these options was exempt from the registration requirements of the Securities Act pursuant to Rule 701.

On January 11, 2007 we issued options to purchase 9,000 units to employees pursuant to the Legacy Reserves LP Long-Term Incentive Plan. The issuance of these options was exempt from the registration requirements of the Securities Act pursuant to Rule 701.

On January 30, 2007, we issued 95,000 units in consideration for our acquisition of producing oil and natural gas properties in West Texas. The issuance of these units was exempt from registration under Section 4(2) of the Securities Act because the issuance did not involve a public offering.

Use of Proceeds from Registered Securities

On January 11, 2007, the Securities and Exchange Commission declared our Registration Statement on Form S-1 (Registration No. 333-138637) effective. Under the registration statement, we issued and sold 6,900,000 units to the public at a price of $19.00 per unit, or $131.1 million. Net proceeds from the sale of units, after underwriter discounts of $9.2 million and estimated offering expenses of $1.9 million were approximately $120.0 million. We used the net proceeds of approximately $120.0 million to:

- repay all of the $115.8 million of indebtedness outstanding under our credit facility;
- use $4.2 million for general partnership purposes.

As of January 18, 2007, we had $115.8 million outstanding under our credit facility. We used the borrowings under the credit facility to:

- fund $65.3 million of the purchase price of producing properties from MBN Properties LP in connection with the closing of our private equity offering;
- fund $13.4 million of the purchase price of producing properties and related operating rights in the South Justis Field;
- fund the $5.6 million purchase price of operated leases in the Farmer Field;
- fund the $17.2 million purchase price of producing properties acquired from Kinder Morgan;
- pay $4.0 million of derivative premiums to cancel and reset oil swaps; and
- for general partnership purposes.

As of December 31, 2006, our credit facility bore interest at 7.29%. The credit facility matures on March 15, 2010.

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, Legacy s 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

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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, Legacy s 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 Legacy for the years ended December 31, 2002 is derived from the consolidated financial statements of the Moriah Group. The selected historical financial data of the Moriah Group for the years ended December 31, 2003, 2004 and 2005 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. 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.

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

	Year Ended December 31,				
	2002	2003	2004	2005(a)	2006(b)
	(In thousands)				
Statement of Operations Data:					
Revenues:					
Oil sales	$ 5,494	$ 7,919	$ 10,998	$ 18,225	$ 45,351
Natural gas sales	2,204	3,697	3,945	7,318	14,446
Realized and unrealized gain (loss) on oil and natural gas swaps	(594)	(283)	(633)	(6,159)	9,289
Total Revenues	7,104	11,333	14,310	19,384	69,086
Expenses:					
Oil and natural gas production	2,586	3,496	4,345	6,376	15,938
Production and other taxes	459	661	928	1,636	3,746
General and administrative	230	543	731	1,354	3,691
Dry hole costs	261	1,465	1		
Depletion, depreciation, amortization and accretion	649	766	883	2,291	18,395
Impairment of long-lived assets		471			16,113
Loss on sale of assets				20	42
Total expenses	4,185	7,402	6,888	11,677	57,925
Operating income	2,919	3,931	7,422	7,707	11,161
Other income (expense):					
Interest income	14	56	419	185	130
Interest expense	(50)	(94)	(213)	(1,584)	(6,645)
Gain on sale of partnership investment			1,292		
Equity in income (loss) of partnerships	(44)	311	183	(495)	(318)
Other	4	3	92	45	29
Income before non-controlling interest	2,843	4,207	9,195	5,858	4,357
Non-controlling interest				1	
Income from continuing operations	$ 2,843	$ 4,207	$ 9,195	$ 5,859	$ 4,357
Earnings from continuing operations per unit					
Basic and fully diluted	$ 0.30	$ 0.44	$ 0.97	$ 0.62	$ 0.26
Distributions per unit (c)	$	$	$	$	$ 0.8974

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	Year Ended December 31,				
	2002	2003	2004	2005(a)	2006(b)
	(In thousands)				
Cash Flow Data:					
Net cash provided by operating activities	$ 3,941	$ 6,799	$ 8,586	$ 14,409	$ 29,590
Net cash provided by (used in) investing activities	$ (1,895)	$ (8,475)	$ 1,023	$ (68,965)	$ (62,505)
Net cash provided by (used in) financing activities	$ (1,993)	$ 1,717	$ (8,958)	$ 55,742	$ 32,022
Capital expenditures	$ 2,741	$ 4,047	$ 3,325	$ 66,915	$ 56,151

	Historical Year Ended December 31,				
	2002	2003	2004	2005(a)	2006(b)
	(In thousands)				
Balance Sheet Data					
Cash and cash equivalents	$ 76	$ 117	$ 769	$ 1,955	$ 1,062
Other current assets	2,643	7,826	5,799	6,316	17,159
Oil and natural gas properties, net of accumulated depletion, depreciation and amortization	7,558	9,954	12,224	77,172	247,580
Other assets	497	651		1,499	7,567
Total assets	$ 10,774	$ 18,548	$ 18,792	$ 86,942	$ 273,368
Current liabilities	$ 3,925	$ 9,157	$ 4,898	$ 4,562	$ 10,834
Long term debt				52,473	115,800
Other long-term liabilities		2,113	1,872	19,998	7,945
Unitholders equity	6,849	7,278	12,022	9,909	138,789
Total liabilities and unitholders equity	$ 10,774	$ 18,548	$ 18,792	$ 86,942	$ 273,368

(a) Reflects 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.

(b) 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.

(c) 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 OPERATION

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 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 Note Regarding Forward-Looking Statements, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

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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 are 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. 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.

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.

Higher oil and natural gas prices have led to higher demand for drilling rigs, operating personnel and field supplies and services, and have caused increases in the costs of those goods and services. To date, the higher sales prices have more than offset the higher drilling and operating costs. Given the inherent volatility of oil and natural gas prices, which are influenced by many factors beyond our control, we plan our activities and budget based on sales price assumptions which historically have been lower than the average sales prices received. We focus our efforts on increasing oil and natural gas production and reserves while controlling costs at a level that is appropriate for long-term operations.

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) recovery methods to repressure the reservoir and recover additional oil, drilling to find additional reserves, restimulating existing wells 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 exploitation projects. Our ability to add reserves through acquisitions and exploitation 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 hedged 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, if any, on any redetermination to our borrowing base under our credit facility.

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

Production and Operating Costs Reporting

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

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Operating Data

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

	Year Ended December 31, 2004	2005(a)	2006(b)
Revenues (in thousands)(c):			
Oil sales	$ 10,998	$ 18,225	$ 45,351
Natural gas sales	3,945	7,318	14,446
Realized gain (loss) on oil swaps	46	(3,531)	(6,667)
Realized gain (loss) on natural gas swaps	(120)		6,405
Unrealized gain (loss) on oil swaps	(679)	(911)	4,338
Unrealized gain (loss) on natural gas swaps	120	(1,717)	5,213
Total revenue	$ 14,310	$ 19,384	$ 69,086
Expenses (in thousands):			
Oil and gas production expenses	$ 4,345	$ 6,376	$ 15,938
Production and other taxes	$ 928	$ 1,636	3,746
General and administrative expenses	$ 731	$ 1,354	3,691
Depletion, depreciation, amortization and accretion expense	$ 883	$ 2,291	18,395
Production:			
Oil (MBbl)	286	354	749
Gas (MMcf)	783	1,027	2,200
Total (MBOE)	416	525	1,116
Average daily production (BOE per day)	1,138	1,438	3,058
Average sales price per unit (including hedges)(c):			
Oil (per Bbl)	$ 36.24	$ 38.94(d)	$ 57.44(e)
Gas (per Mcf)	$ 5.04	$ 5.45	$ 11.85
Combined (per BOE)	$ 34.40	$ 36.92(d)	$ 61.90(e)
Average sales price per unit (including realized hedge gains/losses)(f):			
Oil (per Bbl)	$ 38.61	$ 41.51(d)	$ 51.65(e)
Gas (per Mcf)	$ 4.89	$ 7.13	$ 9.48
Combined (per BOE)	$ 35.74	$ 41.93(d)	$ 53.35(e)
Average sales price per unit (excluding hedges):			
Oil (per Bbl)	$ 38.45	$ 51.48	$ 60.55
Gas (per Mcf)	$ 5.04	$ 7.13	$ 6.57
Combined (per BOE)	$ 35.92	$ 48.65	$ 53.58
Average unit costs per BOE:			
Production costs, excluding production and other taxes	$ 10.44	$ 12.14	$ 14.28
Production and other taxes	$ 2.23	$ 3.12	$ 3.36
General and administrative	$ 1.76	$ 2.58	$ 3.31
Depletion, depreciation and amortization	$ 2.12	$ 4.36	$ 16.48

(a)

Reflects the production and operating results of the PITCO properties from their acquisition on September 14, 2005.

(b) 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.

(c) Includes both the realized and unrealized hedge gains and losses from Legacy s oil and natural gas swaps. Since Legacy does not specifically designate its commodity derivative instruments as cash flow hedges, current earnings reflect a mark-to-market adjustment for these instruments. Unrealized gains and losses represent a current period mark-to-market adjustment for commodity derivatives which will be settled in future periods. See Note 9 on page F-23 for details regarding Legacy s unrealized gains and losses.

(d) Includes the effects of approximately $2.0 million of derivative premiums for the year ended December 31, 2005 to cancel and reset 2006 oil swaps from $51.31 to $59.38 per Bbl and approximately $0.8 million of premiums paid on July 22, 2005 for an option to enter into a $55.00 per Bbl oil swap related to the PITCO acquisition that was not exercised.

(e) Includes the effect of approximately $4.0 million of derivative premiums 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.

(f) Includes only the realized hedge gains (losses) from Legacy s oil and natural gas swaps.

Results of Operations

Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

Legacy s revenues from the sale of oil were $45.4 million and $18.2 million for the years ended December 31, 2006 and 2005, respectively. Legacy s revenues from the sale of natural gas were $14.4 million and $7.3 million for the years ended December 31, 2006 and 2005, respectively. The $27.2 million increase in oil revenues reflects an increase in oil production of 395 MBbls (112%) due primarily to Legacy s purchase of the oil and natural gas properties acquired in the March 15, 2006 formation transactions, or the Legacy Formation, the PITCO acquisition and the South Justis, Farmer Field and Kinder Morgan acquisitions while the realized price excluding the effects of hedging increased $9.07 per Bbl. The $7.1 million increase in natural gas revenues reflects an increase in natural gas production of approximately 1,173 MMcf (114%) due primarily to both the Legacy Formation and the PITCO acquisition while the realized price per Mcf excluding the effects of hedging decreased $0.56 per Mcf. Since the Legacy Formation occurred on March 15, 2006, Legacy s revenues and related volumes for the year ended December 31, 2006 do not reflect the 50 MBbls and 119 MMcf produced by the oil and natural gas properties acquired in that transaction from January 1, 2006 to March 15, 2006. For the year ended December 31, 2006, Legacy recorded $9.3 million of net gains on oil and natural gas swaps comprised of realized losses of $0.3 million from net cash settlements of oil and natural gas swap contracts and net unrealized gains of $9.6 million. Legacy had unrealized net gains from its oil swaps because the fixed price of its oil swap contracts were above the NYMEX index prices at December 31, 2006. As a point of reference, the NYMEX price for light sweet crude oil for the near-month close at December 31, 2006 was $61.05 per Bbl, a price which is less than the average contract prices of Legacy s outstanding oil swap contracts. Legacy had unrealized net gains from its natural gas swaps because the fixed prices of its natural gas swap contracts were above the NYMEX index prices at December 31, 2006. As a point of reference, the NYMEX price for natural gas for the near-month close at December 31, 2006 was $6.30 per MMbtu, a price which is less than the average contract prices of Legacy s outstanding natural gas swap contracts. For the year ended December 31, 2005, Legacy recorded $6.2 million of net losses on oil swaps comprised of a realized loss of $3.5 million from net cash settlements of oil swap contracts and a net unrealized loss of $2.6 million. There were no settlements on natural gas swaps during the year ended December 31, 2005. 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 $15.9 million ($14.28 per Boe) for the year ended December 31, 2006, from $6.4 ($12.14 per Boe) million for the year ended December 31, 2005. Production expenses increased primarily because of (i) $3.6 million related to the PITCO acquisition, (ii) $3.7 million related to the Legacy Formation, (iii) $2.2 million related to the South Justis, Farmer Field and Kinder Morgan acquisitions and (iv) 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 $3.7 million and $1.6 million for the years ended December 31, 2006 and 2005, respectively. Production and other taxes increased primarily because of (i) approximately $0.8 million of taxes related to the PITCO Acquisition, (ii) $0.9 million of taxes related to the Legacy Formation and (iii) higher commodity prices in the 2006 period.

Legacy s general and administrative expenses were $3.7 million and $1.4 million for the years ended December 31, 2006 and 2005, respectively. General and administrative expenses increased approximately $2.1 million between periods primarily due to increased employee costs related to business expansion and approximately $250,000 of costs incurred in connection with our private equity offering.

Legacy s depletion, depreciation, amortization and accretion expense, or DD&A, was $18.4 million and $2.3 million for the years ended December 31, 2006 and 2005, respectively, reflecting primarily $7.3 million of DD&A related to the PITCO acquisition, $6.8 million to the Legacy Formation and $1.0 million to recent acquisitions.

Impairment expense was $16.1 million for the year ended December 31, 2006 involving 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 $129,712 for the year ended December 31, 2006 and $185,308 for the years ended December 31, 2005. The decrease of $55,596 is a result of lower average cash balances for the current period.

Interest expense was $6.6 million and $1.6 million for the years ended December 31, 2006 and 2005, respectively, reflecting higher average borrowings and higher average interest rates in the current period. Legacy borrowed $67.5 million to fund the PITCO acquisition and $65.8 million under its new revolving credit facility at the close of the Legacy Formation.

Legacy recorded equity in loss of partnership of $317,788 and $495,295 for the years ended December 31, 2006 and 2005, respectively. In both periods, 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.

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

Legacy s revenues from the sale of oil were $18.2 million for the year ended December 31, 2005 and $11.0 million for the year ended December 31, 2004. Revenues from the sale of natural gas were $7.3 million for the year ended December 31, 2005 and $3.9 million for the year ended December 31, 2004. The $7.2 million increase in oil revenues reflects an increase in oil production of 67.9 MBbls (24%) due primarily to the PITCO acquisition while the realized price excluding the effects of hedging increased $13.03 per Bbl. The $3.4 million increase in natural gas revenues reflects an increase in natural gas production of approximately 244 MMcf (31%) due primarily to the PITCO acquisition while the realized price per Mcf excluding the effects of hedging increased $2.09 per Mcf. For the year ended December 31, 2005, Legacy recorded $6.2 million of losses on oil and natural gas swaps comprised of a realized loss of $3.5 million and unrealized losses of $2.6 million, as compared to a realized loss of $73,830 for the year ended December 31, 2004 and an unrealized loss of $558,953. Unrealized losses represent a current period mark-to-market adjustment for commodity derivatives which will be settled in future periods. The realized loss of $3.5 million included a $2.0 million loss incurred in June 2005 when Legacy cancelled its existing oil swap contracts which involved fixed prices of approximately $51.31 per Bbl and entered into new oil swaps at fixed prices of $59.38 per Bbl, and includes a premium of $819,000 for an option to enter into a $55.00 per Bbl oil swap related to the PITCO acquisition that was not exercised.

Legacy s oil and natural gas production expenses, excluding production and other taxes, increased to $6.4 million for the year ended December 31, 2005, from $4.3 million for the year ended December 31, 2004. Production expenses increased primarily because of (i) $1.6 million of expenses related to the PITCO acquisition and (ii) 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 $1.6 million and $927,657 for the years ended December 31, 2005 and 2004, respectively. Production and other taxes increased primarily because of (i) approximately $400,000 of taxes related to the PITCO Acquisition and (ii) increased production and increased oil and natural gas prices which is the basis on which severance taxes are paid (percentage of revenue) while ad valorem or property taxes are based on property values, which increase directly with higher oil and natural gas prices.

Legacy s general and administrative expenses were $1.35 million and $731,200 for the years ended December 31, 2005 and 2004, respectively. General and administrative expenses increased approximately $623,200 between periods primarily due to increased employee costs related to business expansion and costs incurred in connection with our private equity offering.

Legacy s depletion, depreciation, amortization and accretion expense, or DD&A, was $2.3 million and $883,457 for the years ended December 31, 2005 and 2004, respectively, reflecting primarily $1.6 million of DD&A related to the PITCO Acquisition.

Legacy recorded interest income of $185,308 for the year ended December 31, 2005 and $419,257 for the year ended December 31, 2004. The decrease of $233,949 is a direct result of lower average cash balances for the current period.

Interest expense was $1.58 million and $213,711 for the years ended December 31, 2005 and 2004, respectively, reflecting higher average borrowings and higher average interest rates in the current period.

No gain on sale of partnership investment was recorded for the year ended December 31, 2005. Legacy realized a gain on sale of partnership investment of $1.3 million for the year ended December 31, 2004 related to the sale of the Accord partnership.

Legacy recorded equity in loss of partnerships of $495,295 for the year ended December 31, 2005 and a gain of $183,474 for the year ended December 31, 2004. The decrease in partnership income is a result of the sale of the Accord partnership interest in April 2004. Legacy recorded equity in loss of partnership of $495,295 related to its investment in MBN Management, LLC, which includes the Moriah Group s 58.36% share of 100% of the MBN Management, LLC loss since the Founding Investors have reported 100% of this loss.

Capital Resources and Liquidity

Legacy s primary sources of capital and liquidity have been proceeds from bank borrowings, cash flow from operations, its private offering in March 2006 and its initial public offering in January 2007. To date, Legacy s primary use of capital has been for the acquisition and exploitation 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, Legacy s working capital was reduced by $4.0 million. During the year ended December 31, 2005, Legacy cancelled (before their original settlement date) a portion of its NYMEX WTI oil swaps covering periods in 2006 and realized a loss of $2.0 million. Legacy, through its ownership of MBN Properties LP, paid a $0.8 million premium for an option to enter into a $55.00 per Bbl oil swap related to the PITCO acquisition

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that was not exercised. As a result, Legacy s working capital was reduced by $2.8 million at December 31, 2005.

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 exploiting additional 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 credit facility, if available, or obtain additional debt or equity financing. Our credit facility imposes certain restrictions on our ability to obtain additional debt financing. Based upon current oil and natural gas price expectations for the year ending December 31, 2007, we anticipate that our cash on hand, cash flow from operations and available borrowing capacity under our credit facility will provide us sufficient working capital to meet our planned capital expenditures of $10.3 million and planned cash distributions of $38.9 million, which reflects the $7.6 million of distributions paid in the first quarter of 2007 and $10.4 million of planned distributions during each of the second, third and fourth quarters of 2007. Please read Financing Activities Our Revolving Credit Facility.

Cash Flow from Operations

Legacy s net cash provided by operating activities was $29.6 million and $14.4 million for the year ended December 31, 2006 and 2005, respectively, with the 2006 period being favorably impacted by higher sales volumes and realized oil and natural gas prices, partially offset by higher expenses.

Legacy s net cash provided by operating activities was $14.4 million and $8.6 million for the years ended December 31, 2005 and 2004, respectively. The increase in net cash provided by operating activities during the year ended December 31, 2005 was due to higher oil and natural gas prices and increased oil and natural gas volumes for that period related to the PITCO acquisition, partially offset by increased expenses, as discussed above in Results of Operations.

Our cash flow from operations is subject to many variables, the most significant of which is the volatility of oil and natural gas prices. Oil 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 exploitation projects, as well as the prices of oil and natural gas.

We enter into hedging arrangements to reduce the impact of oil and natural gas price volatility on our operations. Currently, we use swaps to hedge NYMEX oil and natural gas prices, which do not include the additional net discount that we typically realize in the Permian Basin. At December 31, 2006, we had in place oil and natural gas swaps covering significant portions of our estimated 2007 through 2010 oil and natural gas production. We have hedged approximately 75% of our expected oil and natural gas production for 2007. We have also hedged approximately 70% of our currently expected oil and natural gas production for 2008 through 2010 from existing total proved reserves.

By removing the price volatility from a significant portion of our oil and natural gas production, we have mitigated, but not eliminated, the potential effects of changing prices on our cash flow from operations 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.

The following tables summarize, for the periods indicated, our oil and natural gas swaps currently in place through December 31, 2011. 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 NYMEX price of oil at Cushing, Oklahoma, and NYMEX price of natural gas at Henry Hub on the

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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
2007	741,097	$ 67.40	$ 64.15-$75.70
2008	715,649	$ 67.23	$ 62.25-$73.45
2009	660,613	$ 64.96	$ 61.05-$71.40
2010	575,045	$ 62.94	$ 60.15-$67.80
2011	44,640	$ 67.33	$ 67.33

Calendar Year	Annual Volumes (Mcf)	Average Price per Mcf	Price Range per Mcf
2007	1,558,504	$ 9.56	$ 9.02-$11.83
2008	1,422,732	$ 8.61	$ 7.98-$10.58
2009	1,316,354	$ 8.38	$ 7.77-$10.18
2010	1,218,899	$ 7.99	$ 7.37-$ 9.73

In July 2006, we entered into basis swaps to receive floating NYMEX 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 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 basis swaps currently in place through December 31, 2010.

Calendar Year	Annual Volumes (Mcf)	Basis Range per Mcf
2007	1,560,000	$ (0.88)
2008	1,422,000	$ (0.84)
2009	1,320,000	$ (0.68)
2010	1,200,000	$ (0.57)

Investing Activities Acquisitions and Capital Expenditures

Legacy s cash capital expenditures were $55.9 million for the year ended December 31, 2006. The total includes $7.7 million paid to three charitable foundations in the Legacy Formation for oil and natural gas properties, $8.9 million, $5.6 million and $17.2 million for the purchase of producing oil and natural gas properties in the South Justis Unit from Henry Holding LP, the Farmer Field from Larron Oil Corporation and various oil and natural gas properties from Kinder Morgan, respectively, and $7.0 million of capitalized operating rights related to the South Justis Unit. The balance was invested in exploitation projects.

Legacy s capital expenditures were $66.9 million and $3.3 million for the years ended December 31, 2005 and 2004, respectively. The total for the year ended December 31, 2005 includes $63.9 million in cash ($64.3 million, inclusive of asset retirement obligations) for the acquisition of producing oil and natural gas properties from PITCO and

$1.9 million for exploitation projects. The total for the year ended December 31, 2004 includes $1.6 million for acquisitions and $1.7 million for exploitation projects and of producing properties. The PITCO acquisition was made in anticipation of the formation of Legacy Reserves LP.

We currently anticipate that our drilling budget, which predominantly consists of drilling, recompletion and refracture stimulation projects and one tertiary (CO_2) recovery project will be $10.3 million for the year ending December 31, 2007. Our borrowing capacity under our revolving credit facility is $125.7 million as of March 26, 2007. 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 current oil and natural gas price expectations for the year ending December 31, 2007, we anticipate that we will have sufficient sources of working capital, including our cash flow from operations and available borrowing capacity under our credit facility, to meet our cash obligations including our planned capital expenditures of $10.3 million and planned cash distributions of $38.9 million for the year ending December 31, 2007. 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.

Financing Activities

Moriah Group Credit Agreement

On July 29, 1999, the Moriah Group entered into a Credit Agreement secured by substantially all of its oil and natural gas assets that permitted borrowings up to the lesser of the borrowing base, or $20 million. The agreement provided for certain restrictions including, but not limited to, limitations on additional borrowings, restrictions on use of proceeds, sales of collateral, and distribution to owners. It also required the maintenance of certain quarterly debt ratios. This Credit Agreement was replaced by the Moriah Group Senior Credit Facility described below. There was no outstanding balance since the borrowings under this credit agreement had been repaid in full in August 2005.

Moriah Group Senior Credit Facility

On September 13, 2005, the Moriah Group replaced its Credit Agreement with a Senior Credit Facility with a new lending group that permitted borrowings in the lesser amount of (i) the borrowing base (initially set at $40 million) or (ii) $75 million. Interest on the Senior Credit Facility was payable in accordance with the LIBOR period selected by the Moriah Group at the applicable LIBOR period rate plus 1.5% to 2.0%, or the applicable base rate (ABR) up to a maximum of ABR plus 0.50%, dependent on the percentage of the borrowing base which is drawn. Legacy Reserves LP replaced the Moriah Group Senior Credit Facility concurrently with the closing of our private equity offering with the credit facility described below and repaid the remaining outstanding amount of approximately $18.0 million in full.

Moriah Group Notes Advanced to MBN Properties LP and MBN Management, LLC

MBN Properties LP and MBN Management, LLC, a Delaware limited liability company, (collectively the MBN Group) were formed to acquire oil and natural gas producing properties from PITCO in partnership with Brothers Production Properties, Ltd., and certain third party minority investors. On July 22, 2005, Moriah Properties, Ltd. entered into a $6.5 million subordinated loan agreement with MBN Properties LP. MBN Properties LP borrowed approximately $1.65 million to fund the deposit for the purchase of the PITCO properties.

Also on July 22, 2005, MBN Management, LLC borrowed approximately $0.7 million under a $2 million subordinated loan agreement to fund expenses.

On September 13, 2005, the Moriah Group entered into a $34.0 million subordinated loan agreement with MBN Properties LP as the borrower which replaced the $6.5 million Moriah loan agreement. On September 14, 2005, MBN Properties LP borrowed an additional $17.6 million to fund the remaining purchase price for the PITCO properties.

On March 15, 2006 with proceeds from our private equity offering and borrowings under our new credit facility, each of MBN Properties LP and MBN Management LLC fully repaid their subordinated debt in the amounts, including accrued interest, of $20.5 million and $0.9 million, respectively.

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Our Revolving Credit Facility

At the closing of our private equity offering on March 15, 2006, we entered into a new, four-year, $300 million revolving credit facility with BNP Paribas as administrative agent. Our obligations under the 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, which was initially set at $130 million. The borrowing base is subject to semi-annual redeterminations on April 1 and October 1 of each year. Additionally, either Legacy or the lenders may, once during each calendar year, elect to redetermine the borrowing base between scheduled redeterminations. We also have the right, once during each calendar year, to redetermine 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 662/3% of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the 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 662/3% of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the 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 0.375%, or
- with respect to any Eurodollar loans for any interest period, the London interbank rate, or LIBOR plus an applicable margin between 1.25% and 1.875% per annum.

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 its business; or

engage in certain asset dispositions, including a sale of all or substantially all of our assets.

Our 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 and other similar charges excluding unrealized gains and losses under 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; and

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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 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.

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Contractual Obligations

A summary of our contractual obligations as of December 31, 2006 is provided in the following table.

	Obligations Due in Period				
Contractual Cash Obligations	**2007**	**2008-2009**	**2010-2011**	**Thereafter**	**Total**
Long-term debt	$	$	$ 115,800,000	$	$ 115,800,000
Interest on long-term debt(a)	8,441,820	16,883,640	1,711,492		27,036,952
Management compensation(b)	915,000	1,830,000	915,000		3,660,000
Office lease	134,556	327,445	370,093		832,094
Total contractual cash obligations	$ 9,491,376	$ 19,041,085	$ 118,796,585	$	$ 147,329,046

(a) Based upon our interest rate of 7.29% under our revolving credit facility as of December 31, 2006.

(b) Does not include any liability associated with management compensation subsequent to the 2010-2011 period as there is no estimated termination date of the employment agreements.

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. Legacy based its 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 the 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 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, 2006 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 some significant calculations, 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. 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 and natural gas production by reducing our exposure to price fluctuations. Currently, these transactions are swaps whereby we exchange our floating price for our oil and natural gas for a fixed price with qualified and creditworthy counterparties (currently BNP Paribas and Bank of America). Our existing oil and natural gas swaps are with

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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 and natural gas prices. Therefore, the mark-to-market of these instruments is recorded in current earnings. While we are not internally preparing an estimate of the current market value of these derivative instruments, we use market value statements from each of our counterparties 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 2010. Taking into account the mark-to-market liabilities and assets recorded as of December 31, 2006, 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 (FIN) No. 46 (revised December 2003) 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. Legacy s non-controlling income of $538 for the year ended December 31, 2005 represents the loss of MBN Properties LP attributable to the other owners equity interests. As we have acquired all of MBN Properties LP s properties in the formation transactions on March 15, 2006, after that date there are no remaining non-controlling interests.

Recently Issued Accounting Pronouncements

In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109.* Interpretation No. 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes.* This Interpretation is effective for fiscal years beginning after December 15, 2006, and Legacy will adopt it in the first quarter of 2007. Legacy does not expect the adoption of Interpretation No. 48 to have a material impact on its financial statements and related disclosures.

In September 2006, the Securities and Exchange Commission (SEC) issued Staff Accounting Bulletin No. 108 (SAB 108). Due to diversity in practice among registrants, SAB 108 expresses SEC staff views regarding the process by which misstatements in financial statements are evaluated for purposes of determining whether financial statement restatement is necessary. SAB 108 is effective for fiscal years ending after November 15, 2006. The adoption of SAB 108 did not have a material impact on Legacy s financial position or results of operations.

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 generally accepted account principles and expands disclosure related to the use of fair value measures in financial statements. The Statement is to be effective for Legacy s financial statements issued in 2008; however, earlier application is encouraged. Legacy is currently evaluating the timing of adoption. The Statement will affect fair value measurements we make after adoption.

In February 2007, the FASB issued Statement of Financial Accounting Standards No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities   Including an Amendment of FASB Statement No. 115.* Statement No. 159 permits entities to choose to measure certain financial instruments and other items at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. Unrealized gains and losses on any items for which Legacy elects the fair value measurement option would be reported in earnings. Statement No. 159 is effective for fiscal years beginning after November 15, 2007. However, early adoption is permitted for fiscal years beginning on or before November 15, 2007, provided Legacy also elects to apply the provisions of Statement No. 157, *Fair Value Measurements*, at the same time. Legacy is currently assessing the effect, if any, the adoption of Statement No. 159 will have on its financial statements and related disclosures.

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.

We periodically enter into and anticipate entering into hedging arrangements with respect to a portion of our projected oil and natural gas production through various transactions that hedge 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 right 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 hedging 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, 2006, the fair market value of Legacy s derivative positions was a net asset of $3.1 million. As of December 31, 2005, the fair market value of Legacy s derivative positions, not including the liabilities of MBN Properties LP, was a liability of $1.9 million. Additionally, the fair market value of MBN Properties LP s oil and natural gas hedge position as of December 31, 2005, was a liability of $1.45 million. Legacy Reserves LP has assumed these hedge positions. The oil and natural gas swaps for 2007 through December 31, 2010 are tabulated in the table presented above under Cash Flow from Operations.

If oil prices decline by $1.00 per Bbl, then the standardized measure of our combined proved reserves as of December 31, 2006 would decline from $240.6 million to $235.0 million, or 2.3%. If natural gas prices decline by $0.10 per Mcf, then the standardized measure of our combined proved reserves as of December 31, 2006 would decline from $240.6 million to $239.3 million, or 0.5%.

Interest Rate Risks

At December 31, 2006, Legacy had debt outstanding of $115.8 million, which incurred interest at floating rates in accordance with its revolving credit facility and the subordinated notes payable. The average annual interest rate incurred by Legacy for year ended December 31, 2006 was 7.27%. A 1% increase in LIBOR on

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Legacy s outstanding debt as of December 31, 2006 would result in an estimated $1.2 million increase in annual interest expense. Historically, Legacy has not entered into interest rate derivative transactions to mitigate its interest rate risk.

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, 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 Partner s 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 Partner s 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, 2006. Based upon that evaluation and subject to the foregoing, our General Partner s Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective to accomplish their objectives.

Our General Partner s 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, 2006, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

This annual report does not include a report of management s assessment regarding internal control over financial reporting or an attestation report of Legacy s registered public accounting firm due to a transition period established by rules of the Securities and Exchange Commission for non-accelerated filers.

ITEM 9B. *OTHER INFORMATION*

None.

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PART III

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

Management of Legacy Reserves LP

The directors and officers of Legacy Reserves GP, LLC, as our general partner, manage our operations and activities. Our general partner is not elected by our unitholders and will not be subject to re-election on a regular basis in the future. Other than through their ability to elect directors of our general partner as described below, unitholders will not be entitled to directly or indirectly participate in our management or operation.

Our general partner owes a fiduciary duty to our unitholders. Our general partner will be liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically nonrecourse to it. Our general partner therefore may cause us to incur indebtedness or other obligations that are nonrecourse to it.

The limited liability agreement of our general partner provides for a seven member board of directors.

Our unitholders, including affiliates of our general partner, are entitled to annually elect all of the directors of our general partner.

Director Independence

Three members of the board of directors of our general partner serve on a conflicts committee to review specific matters that the board believes may involve conflicts of interest. The conflicts committee will determine if the resolution of the conflict of interest is fair and reasonable to us. The members of the conflicts committee may not be officers or employees of our general partner or directors, officers, or employees of its affiliates, and must meet the independence and experience standards established by any national securities exchange on which our securities may be listed and the Exchange Act and other federal securities laws. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by our general partner of any duties it may owe us or our unitholders. In addition, the board of directors of our general partner has an audit committee of three directors who meet the independence and experience standards established by the NASDAQ Global Market and the Exchange Act. The audit committee will review our external financial reporting, recommend engagement of our independent auditors and review procedures for internal auditing and the adequacy of our internal accounting controls. The board of directors of our general partner also has a compensation committee, consisting of three independent members, with the limited function of administering our long-term incentive plan and any future compensation plans. Additionally, the board of directors of our general partner has a nominating and governance committee, consisting of three independent members, that will nominate candidates to serve on the board of directors of our general partner.

Independent members of the board of directors of our general partner serve as the members of the conflicts (Messrs. Sullivan (chairman), Lawrence and Vann), audit (Messrs. Lawrence (chairman), Sullivan and VanLoh), compensation (Messrs. Vann (chairman), VanLoh and Sullivan) and nominating and governance (Messrs. Sullivan (chairman), Lawrence and Vann) committees. We are not required to have a majority of independent directors on the board of directors of our general partner; however, we currently have a majority of independent directors on the board of directors of our general partner.

The audit committee has been established in accordance with Section 10A-3 of the Exchange Act. The board of directors of our general partner has appointed Messrs. Lawrence, Sullivan and VanLoh as members of the audit committee. Each of the members of the audit committee have been determined by the board of directors to be independent under the NASDAQ s standards for audit committee members to serve on its audit committee. In addition, the board of directors has determined that at least one member of the audit committee (Mr. Lawrence) has such accounting or related financial management expertise sufficient to qualify such person as the audit committee financial expert in accordance with Item 401 of Regulation S-K. A description of the qualifications of Mr. Lawrence may be found in this Item 10. under Directors and Executive Officers of the Registrant.

Code of Ethics and Business Conduct

The board of directors of our general partner has adopted a Code of Ethics and Business Conduct applicable to officers, directors of our general partner and our employees, including the principal executive officer, principal financial officer, principal accounting officer and controller, or those persons performing similar functions, of our general partner. The Code of Ethics and Business Conduct is available on our website at www.legacylp.com and in print to any unitholder who requests it. Amendments to, or waivers from, the Code of Ethics and Business Conduct will also be available on our website and reported as may be required under SEC rules; however, any technical, administrative or other non-substantive amendments to the Code of Ethics and Business Conduct may not be posted. Please note that the preceding Internet address is for information purposes only and is not intended to be a hyperlink. Accordingly, no information found or provided at that Internet addresses or at our website in general is intended or deemed to be incorporated by reference herein.

Directors and Executive Officers of our General Partner

The following table shows information for the directors and executive officers of our general partner. Directors are elected for one-year terms.

Name	**Age**	**Position with Legacy Reserves GP, LLC**
Cary D. Brown	40	Chief Executive Officer and Chairman of the Board
Steven H. Pruett	45	President, Chief Financial Officer and Secretary
Kyle A. McGraw	47	Director, Executive Vice President Business Development and Land
Paul T. Horne	45	Vice President Operations
William M. Morris	54	Vice President, Chief Accounting Officer and Controller
Dale A. Brown	64	Director
G. Larry Lawrence	55	Director and Member of Audit, Conflicts and Nominating Committees
William D. Sullivan	50	Director and Member of Audit, Compensation, Conflicts and Nominating Committees
S. Wil VanLoh, Jr.	36	Director and Member of Audit and Compensation Committees
Kyle D. Vann	59	Director and Member of Compensation, Conflicts and Nominating Committees

Directors of our general partner hold office until the earlier of their death, resignation, removal or disqualification or until their successors have been elected and qualified. Officers of our general partner serve at the discretion of the board of directors. None of our executive officers and directors are related except for Dale A. Brown and Cary D. Brown, who are father and son.

Cary D. Brown is Chairman of the board of directors of our general partner and Chief Executive Officer of our general partner and has served in such capacities since our founding in October 2005. Prior to October 2005, Mr. Brown co-founded two businesses, Moriah Resources, Inc. and Petroleum Strategies, Inc. Moriah Resources, Inc. was formed in 1992 to acquire oil and natural gas reserves. Petroleum Strategies, Inc. was formed in 1991 to serve as a qualified intermediary in connection with the execution of Section 1031 transactions for major oil companies, public independents and private oil and natural gas companies.

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Mr. Brown has served as Executive Vice President of Petroleum Strategies, Inc. since its inception in 1991. Mr. Brown served as an auditor for Grant Thornton in Midland, Texas from January 1990 to June 1991 and for Deloitte & Touche in Houston, Texas from June 1989 to December 1989. Mr. Brown is a certified public accountant. In 1995, Mr. Brown also founded and organized The Executive Oil Conference held in Midland, Texas, which draws over 300 oil and natural gas industry professionals each year. Mr. Brown has a Bachelors of Business Administration, with honors, from Abilene Christian University. Mr. Brown has 17 years of experience in the oil and natural gas industry with 15 years of experience in the Permian Basin.

Steven H. Pruett is President, Chief Financial Officer and Secretary of our general partner and has served as President and Chief Financial Officer since our founding in October 2005. From January 2005 until he joined our general partner, Mr. Pruett served as a Managing Director at Quantum Energy Partners, a private equity group focused in the energy industry. From August 2004 to December 2004, Mr. Pruett was the President of PSI Management LLC, where his focus was investing in oil and natural gas projects in the Permian Basin. From June 2002 to July 2004, Mr. Pruett was the President of Petroleum Place and its subsidiary, P2 Energy Solutions, an acquisition and divestment advisor and accounting and land software systems developer serving over 100 public oil and natural gas companies. From June 2001 to June 2002, Mr. Pruett was employed by First Permian as its President and Chief Executive Officer until its sale to Energen Corporation. From April 2000 to May 2001, Mr. Pruett served as a Vice President of Enron North America Corp., where he managed 12 active oil and natural gas joint ventures and served as chairman of CGAS, an Appalachian oil and natural gas company. From April 1995 to March 2000, Mr. Pruett was President and Chief Executive Officer of First Reserve Oil & Gas Co., a Permian Basin and Oklahoma oil and natural gas property acquisition and exploitation company. Mr. Pruett has a Bachelor of Science in Petroleum Engineering, with high honors, from the University of Texas and a Masters of Business Administration from Harvard Business School where he was a Baker Scholar. Mr. Pruett has 23 years of experience in the oil and natural gas industry with 18 years of experience in the Permian Basin.

Kyle A. McGraw is a member of the board of directors of our general partner and also serves as the Executive Vice President Business Development and Land of our general partner and has served in such capacities since our founding in October 2005. Mr. McGraw joined Brothers Production Company in 1983, and has served as its General Manager since 1991 and became President in 2003. During his 23 year tenure at Brothers Production Company, Mr. McGraw has served in numerous capacities including reservoir and production engineering, acquisition evaluation and land management. Mr. McGraw is a registered professional engineer (inactive status) in the state of Texas. Mr. McGraw has a Bachelor of Science in Petroleum Engineering from Texas Tech University. Mr. McGraw has 24 years of experience in the oil and natural gas industry in the Permian Basin.

Paul T. Horne is Vice President Operations of our general partner and has served in such capacity since our founding in October 2005. From January 2000 to the present, Mr. Horne has served as Operations Manager of Moriah Resources, Inc. From January 1985 to January 2000, Mr. Horne worked for Mobil E&P U.S. Inc. in a variety of petroleum engineering and operations management roles primarily in the Permian Basin. Mr. Horne has a Bachelor of Science in Petroleum Engineering from Texas A&M University. Mr. Horne has 23 years of experience in the oil and natural gas industry with 21 years of experience in the Permian Basin.

William M. Morris is Vice President, Chief Accounting Officer and Controller of our general partner and has served in such capacity since our founding in October 2005. From January 2000 until he joined our general partner in October 2005, Mr. Morris served as Financial Reporting Manager of Titan Exploration Inc. (from January 2000 through May 2000) and continued in that position upon Titan Exploration Inc. s merger with the Permian Basin Business Unit of Unocal to form Pure Resources, Inc. (from May 2000 to January 2003) and most recently as a Financial Manager for Pure Resources, Inc. (from February 2003 to September 2005). Mr. Morris is a certified public accountant. Mr. Morris has a Bachelor of Science in Applied Mathematics, with honors, from the School of Engineering and Applied Science of the University of Virginia and a Master of Business Administration from Colgate Darden Graduate School of Business Administration of the University of Virginia. Mr. Morris has 26 years of experience in the oil and natural gas industry with 25 years of experience in the Permian Basin.

Dale A. Brown is a member of the board of directors of our general partner and has served in such capacity since our founding in October 2005. Mr. Brown has been President of Moriah Resources, Inc. since its inception in 1992 and President of Petroleum Strategies, Inc. since he co-founded it in 1991 with his son, Cary D. Brown. Mr. Brown is a certified public accountant. Mr. Brown has a Bachelor of Science in Accounting from Pepperdine University.

G. Larry Lawrence has been a member of the board of directors of our general partner since May 1, 2006. Since June 2006, Mr. Lawrence has been self employed as a management consultant doing business as Crescent Consulting. From May 2004 through April 2006 Mr. Lawrence served as Controller of Pure Resources, an exploration and production company and a wholly owned subsidiary of Unocal Corporation which was acquired by Chevron Corporation. From June 2000 through May 2004, Mr. Lawrence was a practice manager of the Parson Group, LLC, a financial management consulting firm whose services included Sarbanes Oxley engagements with oil and natural gas industry clients. From 1973 through May 2000, Mr. Lawrence was employed by Atlantic Richfield Company (ARCO) where he most recently (from 1993 through 2000) served as Controller of ARCO Permian. Mr. Lawrence has a Bachelor of Arts in Accounting, with honors, from Dillard University.

William D. (Bill) Sullivan was appointed to the board of directors of our general partner upon completion of our private equity offering on March 15, 2006. Since May 2004, Mr. Sullivan has served as a director of St. Mary Land & Exploration Company, a publicly traded exploration and production company and Targa Resources GP, LLC, (the general partner of Targa Resource Partners LP) since February 14, 2007. From May 2004 through its sale in August 2005, Mr. Sullivan served as a director of Gryphon Exploration Company, a privately held exploration and production company. Prior to joining the board of directors of St. Mary Land & Exploration Company and Gryphon Exploration Company, Mr. Sullivan was employed in various capacities by Anadarko Petroleum Corporation from 1981 to August 2003, most recently as Executive Vice President, Exploration and Production (from August 2001 through August 2003). From June 15, 2005 to August 5, 2005, Mr. Sullivan was president and CEO of Leor Energy L.P., a privately held exploration and production company. Mr. Sullivan has a Bachelor of Science in Mechanical Engineering, with high honors, from Texas A&M University.

S. Wil VanLoh, Jr. is a member of the board of directors of our general partner and has served in such capacity since our founding in October 2005. Since 1997, Mr. VanLoh has been a Managing Partner of Quantum Energy Partners, a private equity firm specializing in the energy industry. Prior to co-founding Quantum Energy Partners in 1997, Mr. VanLoh co-founded Windrock Capital, Ltd., an energy investment banking firm specializing in raising private equity and providing merger, acquisition and divestiture advice for energy companies. Before co-founding Windrock Capital, Ltd. In 1994, Mr. VanLoh was an investment banking analyst in Kidder, Peabody & Co. s Natural Resources Group and also with NationsBank Investment Banking where he worked on corporate debt and equity financings, mergers and acquisitions, and other highly structured transactions for energy and energy-related companies. Mr. VanLoh currently serves on the boards of a number of portfolio companies of Quantum Energy Partners, all of which are private energy companies. Mr. VanLoh currently serves as a board member and treasurer of the Houston Producers Forum and a member of the IPAA Finance Committee. Mr. VanLoh has a Bachelor of Business Administration from Texas Christian University.

Kyle D. Vann was appointed to the board of directors of our general partner upon completion of our private equity offering on March 15, 2006. From 1979 through December 2004 Mr. Vann was employed by Koch Industries most recently serving as Chief Executive Officer of Entergy Koch, LP, an energy trading and transportation company, from its inception in February 2001 through its sale at year end 2004. Mr. Vann continues to serve Entergy as a consultant and serves on the board of Texon, LP, a private petroleum transportation company. On May 8, 2006, Mr. Vann was appointed to the board of directors of Crosstex Energy, L.P., a publicly traded midstream master limited partnership.

Mr. Vann has a Bachelor of Science in Chemical Engineering from the University of Kansas.

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Reimbursement of Expenses of Our General Partner

Our general partner will not receive any management fee or other compensation for its management of us. Our general partner and its affiliates will, however, be reimbursed for all expenses incurred on our behalf. The partnership agreement provides that our general partner will determine the expenses that are allocable to us. There is no limit on the amount of expenses for which our general partner and its affiliates may be reimbursed.

ITEM 11. *EXECUTIVE COMPENSATION*

DIRECTOR COMPENSATION

Officers or employees of our general partner and its affiliates who also serve as directors of our general partner did not receive additional compensation for their board service in 2006. In accordance with this policy, neither Cary D. Brown nor Kyle McGraw received any compensation for their service as a director in 2006. Each non-employee director and independent director was entitled to receive an annual retainer of $25,000 and up to $1,000 for each board of directors and committee meeting in excess of four per year. While Messrs. Dale A. Brown and VanLoh opted not to accept the annual retainer of $25,000 and meeting fees for their service as a Director in 2006, they will each be paid the annual retainer and meeting fees in 2007.

Each non-employee director and independent director receives a grant of 1,750 units pursuant to the Legacy Reserves LP Long-Term Incentive Plan (the LTIP) effective upon appointment to the board of directors of our general partner. In accordance with this policy, on May 1, 2006, Messrs. Dale A. Brown, Lawrence, Sullivan, VanLoh, Jr. and Vann received initial grants of 1,750 units for their service on our board of directors during 2006.

In addition to the annual retainer and units paid to board members, the chairman of our audit, conflicts, compensation, and nominating and corporate governance committees each received an annual retainer for their additional service. For 2006, Mr. Lawrence received $10,000 as chairman of the audit committee, Mr. Sullivan received $5,000 as chairman of both the conflicts committee and nominating and corporate governance committee, and Mr. Vann received $5,000 as chairman of the compensation committee.

Our directors are eligible to receive awards under the LTIP but do not participate in any non-equity incentive plan, pension plan, or deferred compensation plan. Each non-employee director and independent director is reimbursed for out-of-pocket expenses in connection with attending meetings of the board of directors or committees. Each director will be indemnified by us for actions associated with being a director to the fullest extent permitted under Delaware law.

The following table sets forth the aggregate compensation awarded to, earned by or paid to our directors during 2006.

Director Compensation for the 2006 Fiscal Year

	Fees Earned		Non-Equity	Change in Pension Value and Nonqualified	

Name	or Paid in Cash ($)	Unit Awards ($)(a)	Option Awards ($)	Incentive Plan Compensation ($)	Deferred Compensation Earnings	All Other Compensation ($)	Total ($)
Dale A. Brown	(b)	$ 29,750					$ 29,750
G. Larry Lawrence	$ 40,000	$ 29,750					$ 69,750
William D. Sullivan	$ 36,000	$ 29,750					$ 65,750
S. Wil VanLoh, Jr.	(b)	$ 29,750					$ 29,750
Kyle D. Vann	$ 35,000	$ 29,750					$ 64,750

(a) Reflects the aggregate grant date fair value computed in accordance with FAS 123R. All of the units were priced at $17 per unit, which reflects the offering price of our units in our private equity offering closed March 15, 2006.

(b) While Messrs. Dale A. Brown and VanLoh opted not to receive the retainer and meeting fees for their service on our board in 2006, they will each be paid the annual retainer and meeting fees in 2007.

EXECUTIVE OFFICER COMPENSATION

REPORT OF THE COMPENSATION COMMITTEE

The Compensation Committee of the Board of Directors of Legacy Reserves GP, LLC held one meeting during fiscal year 2006. The Compensation Committee has reviewed and discussed the Compensation Discussion and Analysis with management. Based upon such review, the related discussions and such other matters deemed relevant and appropriate by the Compensation Committee, the Compensation Committee has recommended to the Board of Directors of Legacy Reserves GP, LLC that the Compensation Discussion and Analysis be included in this annual report on Form 10-K.

Members of the Compensation Committee of the Board of Directors of Legacy Reserves GP, LLC:

Kyle D. Vann (Chair)
William D. Sullivan
S. Wil VanLoh, Jr.

Compensation Discussion and Analysis

The following discussion and analysis of compensation arrangements of the named executive officers of our general partner, Legacy Reserves GP LLC, should be read together with the compensation tables and related disclosures set forth below.

Introduction

Our general partner manages our operations and activities through its board of directors. We reimburse our general partner for direct and indirect general and administrative expenses incurred on our behalf, including the compensation of our general partner s executive officers. Our general partner has not incurred any reimbursable expenses related to the compensation of our general partner s executive officers for their management of us. Currently, our general partner s executive officers are employed by our wholly owned subsidiary, Legacy Reserves Services, Inc., and are directly compensated for their management of us pursuant to their employment agreements. Please read Employment Agreements.

The five named executive officers of our general partner are Cary D. Brown, Chairman and Chief Executive Officer, Steven H. Pruett, President, Chief Financial Officer and Secretary, Kyle A. McGraw, Executive Vice President of Business Development and Land, Paul T. Horne, Vice President of Operations, and William M. Morris, Vice President, Chief Accounting Officer and Controller.

Corporate Governance

Compensation Committee Authority

Executive officer compensation is administered by the compensation committee of the board of directors of our general partner, which is composed of three members, Messrs. Vann, VanLoh, Jr., and Sullivan (Messrs. Vann and Sullivan joined the board of directors in 2006). The board of directors appoints the compensation committee members and delegates to the compensation committee the direct responsibility for setting compensation for named executive officers, establishing equity and non-equity incentive plans, and administering our LTIP.

The board of directors has determined that each committee member is independent under the listing standards of the Nasdaq Global Market, the Securities and Exchange Commission rules and the relevant securities laws, and that each member is an outside director as defined in Section 162(m) of the Internal Revenue Code of 1986, as amended. The compensation committee met once in 2006.

Compensation Committee Interlocks and Insider Participation

No current executive officer served as a member of the board or directors or compensation committee of any other entity (other than our subsidiaries) that has or has had one or more executive officers serving as a member of the board of directors of our general partner or the compensation committee of our general partner.

Role of Compensation Experts in Determining 2006 Executive Officer Compensation

The compensation committee is authorized to obtain at company expense compensation surveys, reports on the design and implementation of compensation programs for directors, officers and employees, and other data and documentation as the compensation committee considers appropriate. In addition, the compensation committee has the sole authority to retain and terminate any outside counsel or other experts or consultants engaged to assist it in the evaluation of compensation of our directors and executive officers, including the sole authority to approve such consultants fees and other retention terms. The compensation committee did not retain the services of a compensation consultant to assist in the evaluation and design of 2006 executive officer compensation, nor did it consult any compensation surveys or reports. In connection with Legacy s initial public offering in January 2007, the compensation committee retained a compensation consultant for 2007. Salaries for 2006 were set prior to the formation of our compensation committee. Factors we considered in determining the salaries include:

- the qualifications, skills and experience level of the respective named executive officer;
- the position, role and responsibility of the respective named executive officer in the company; and
- the direct experience of the respective named executive officer in the oil industry as a whole, and specifically, the Permian Basin.

Executive Officer Compensation Strategy and Philosophy

Our executive officer compensation strategy is designed to attract and retain highly qualified executive officers and to align their interests with those of investors by linking significant components of executive officer compensation with the achievement of our overall goals of growth and financial strength. As many of our executive officers hold units in the partnership, we have attempted to maintain competitive levels of compensation while focusing on the growth of our business. Through this approach, our executives receive salaries for the market value of their services and their performance is further rewarded through the distributions they receive on their holdings of our units. We have limited the existence of non-equity incentive awards to date due to our desire to conserve cash which fuels our growth and reduces operating expenses.

Although we do not currently maintain any plan with threshold, target, or maximum amounts of awards that can be earned based on predetermined levels of performance, we granted unit options to each of our named executive officers during 2006. These grants were designed to reward our executives for their performance in assembling a private offering of our securities during the year and encourage their further efforts in growing our business and pursuing an initial public offering of our units. Due to our desire to treat our executive officers equally, each executive received a grant of 20,000 unit options.

We may develop equity and non-equity incentive plans in the future and make bonus payments to our named executive officers.

At our named executive officers 2006 compensation levels, we did not believe that Internal Revenue Code Section 162(m) would be applicable and accordingly, did not consider it in setting 2006 compensation levels.

Components of Compensation

Base Salaries

It is the intent of the compensation committee to have the base salaries of our named executive officers reviewed on an annual basis as well as at the time of a promotion or other material change in responsibilities.

Adjustments in base salary may be based on an evaluation of individual performance, our company-wide performance and the individual s contribution to our performance. Upon Mr. Morris assumption of the role of Chief Accounting Officer, Mr. Morris base salary was raised by $25,000 to its current level to reflect his additional responsibilities. No other salary adjustments were made in 2006. See Summary Compensation Table.

Long-Term Incentive Compensation

Overview

We currently administer long-term incentive compensation awards through our LTIP adopted in March 2006. The plan is administered by the compensation committee of the board of directors of our general partner and permits the grant of awards covering an aggregate of 2,000,000 units. The purpose of the plan is to promote the interests and our unitholders by encouraging our employees, directors and other service providers to acquire or increase their equity interest in us, thereby giving them the added incentive to work toward our continued growth and success. The plan permits awards of unit grants, restricted units, phantom units, unit options, unit appreciation rights, performance based units and other forms of equity compensation.

As of December 31, 2006, grants of awards covering 333,866 units have been made including 65,116 restricted units and 268,750 unit options. We have awarded unit options as the primary form of equity compensation. We selected this form because of the favorable accounting and tax treatment and the expectation by key employees that part of their compensation would be derived from options to purchase units in the partnership.

Unit option awards have been tied to the performance of the named executive officers in expanding the business and preparing us for a private offering of our units. All unit-based awards we have made have been time-based. Time-based awards vest in accordance with vesting schedules determined by our board of directors and our compensation committee. The unit options and restricted units we awarded to the named executive officers in 2006 vest one-third each year over three years. Our belief is that time-based awards more closely align our executives interest with unitholders by providing a greater incentive for long-term performance.

We consider long-term equity incentive compensation to be an important element of our compensation program for named executive officers. We believe that meaningful equity participation by each named executive officer to be a strong motivating factor that will result in significant increases in value and in growth. This belief is reflected in the aggregate awards of unit options and restricted units that have been made to named executive officers that did not already have a significant interest in our units.

Our general partner s board of directors, or its compensation committee, in its discretion may terminate, suspend or discontinue the LTIP at any time with respect to any award that has not yet been granted. Our general partner s board of directors, or its compensation committee, also has the right to alter or amend the LTIP or any part of the plan from time to time, including increasing the number of units that may be granted, subject to unitholder approval as required by the exchange upon which the units are listed at that time. However, no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of the participant.

Unit grants

The LTIP permits the grant of units. A unit grant is a grant of units that vests immediately upon issuance.

Restricted Units and Phantom Units

A restricted unit is a unit that is subject to forfeiture prior to the vesting of the award. A phantom unit is a notional unit that entitles the grantee to receive a unit upon the vesting of the phantom unit or, in the discretion of the compensation committee, cash equivalent to the value of a unit. The compensation committee may make grants under the plan of restricted units and phantom units to employees, consultants and directors containing such terms, consistent with the plan, as the compensation committee shall determine. The compensation committee will determine the period over which the restricted units and phantom units granted to employees, consultants and directors will vest. The compensation committee may base vesting upon the achievement of specified financial objectives or on the grantee s completion of a period of service. In addition, the restricted units and phantom units will vest upon a change of control of Legacy Reserves LP or our general partner, unless provided otherwise by the compensation committee in the award agreement.

If the grantee s employment, service relationship or membership on the board of directors terminates for any reason, the grantee s restricted units and phantom units will be automatically forfeited unless, and to the extent, the compensation committee provides otherwise in the award agreement or waives (in whole or in part) any such forfeiture. Units to be delivered in connection with the grant of restricted units or upon the vesting of phantom units may be units acquired by us on the open market, or from any other person or we may issue new units, or any combination of the foregoing. Our general partner is entitled to reimbursement by us for the cost incurred in acquiring units. Thus, the cost of the restricted units and the delivery of units upon the vesting of phantom units will be borne by us. If we issue new units in connection with the grant of restricted units or upon vesting of the phantom units, the total number of units outstanding will increase. The compensation committee, in its discretion, may provide for tandem distribution rights with respect to restricted units and grant tandem distribution equivalent rights with respect to phantom units that entitle the holder to receive cash equal to any cash distributions made on units prior to the vesting of a restricted or phantom unit.

Unit Options and Unit Appreciation Rights

The LTIP permits the grant of options covering units and the grant of unit appreciation rights. A unit appreciation right is an award that, upon exercise, entitles the participant to receive the excess of the fair market value of a unit on the exercise date over the exercise price established for the unit appreciation right. Such excess may be paid in units, cash, or a combination thereof, as determined by the compensation committee in its discretion. The compensation committee will be able to make grants of unit options and unit appreciation rights under the plan to employees, consultants and directors containing such terms as the committee shall determine consistent with the plan. Unit options and unit appreciation rights may not have an exercise price that is less than the fair market value of the units on the date of grant. In general, unit options and unit appreciation rights granted will become exercisable over a period determined by the compensation committee. In addition, the unit options and unit appreciation rights will become exercisable upon a change in control of Legacy Reserves LP or our general partner, unless provided otherwise by the committee in the award agreement. The compensation committee, in its discretion may grant tandem distribution equivalent rights with respect to unit options and unit appreciation rights.

Upon exercise of a unit option (or a unit appreciation right settled in units), we will acquire units on the open market or from any other person or we may issue new units, or any combination of the foregoing. If we issue new units upon exercise of the unit options (or a unit appreciation right settled in units), the total number of units outstanding will increase, and our general partner will pay us the proceeds it receives from an optionee upon exercise of a unit option. The availability of unit options and unit appreciation rights is intended to furnish additional compensation to employees, consultants and directors and to align their economic interests with those of unitholders.

In 2006, we made awards of unit options and restricted units under our LTIP. On March 15, 2006, we made a grant of 35,077 restricted units to Mr. Morris in connection with his employment agreement that are subject to three year vesting. Mr. Morris restricted unit award is also subject to accelerated vesting under certain conditions. On July 17, 2006, we made grants of 20,000 unit options that are subject to three year vesting to each of our named executive officers to reward their efforts in completing our March 2006 private offering.

Unit Option Practices

Due to our limited operating history, we have not yet established any set methodology for awarding unit options. Although our LTIP permits us to award options under a variety of circumstances, we have not yet analyzed a uniform standard for the type of awards that we will make or any standard vesting schedule tied to the options or other rights we may grant. We have not back-dated any option awards. The option grants we have made to date had an exercise price that corresponded with the offering price to purchasers of our units in a private offering we conducted in March 2006, the price at which our units traded on the Portal Market, or the price to the public of our units in our January 2007 initial public offering. We anticipate that any option grants we may make in the future will have an exercise price equal to the market value of our units at the close of trading on the date of the grant.

As a privately owned partnership, there had been no public market for our units. Accordingly, in 2006, we had no program, plan or practice pertaining to the timing of unit option grants to executive officers coinciding with the release of material non-public information.

Perquisites and Other Personal Benefits

Our principal executive office is in Midland, Texas, and our named executive officers are required to travel often due to the expansive nature of the oil and natural gas business. Due to the frequent travel involved, our employees are not required to maintain their primary residences in Midland, and we pay for certain travel to and from their residences. In 2006, we required Mr. Pruett to discharge a significant portion of his executive responsibilities in Midland. Accordingly, we deemed it appropriate and economically efficient to reimburse Mr. Pruett for airline flights and car rental expenses when traveling to and from our office in Midland. Because Mr. Pruett s principal city of residence is Houston, we determined for disclosure purposes and in considering his compensation that the amounts allocable to Mr. Pruett for his air transportation to and from Midland should be viewed as perquisites. See Summary Compensation Table below for the amount attributable to Mr. Pruett for this benefit in 2006.

We maintain a 401(k) plan. The plan permits eligible full-time employees, including named executive officers, to make voluntary, pre-tax contributions to the plan up to a specified percentage of compensation, subject to applicable tax limitations. We may make a discretionary matching contribution to the plan for each eligible employee equal to 4.0% of an employee s annual compensation not in excess of $220,000 for 2006, subject to applicable tax limitations. Eligible employees who elect to participate in the plan are generally vested in any matching contribution after commencement of employment with the company. The plan is intended to be qualified under Section 401(a) of the Internal Revenue Code so that contributions to the plan, and income earned on plan contributions, are not taxable to employees until withdrawn from the plan, and so that contributions, if any, will be deductible when made.

We maintain an employee benefit plan that provides our employees with the opportunity to enroll in our health, dental and life insurance plans. We pay all of our employees health and life insurance premiums. Our dental plan requires the employee to pay a portion of the premium, with the company picking up the remainder. We provide these benefits so that we will remain competitive in the employment market and offer the benefits to all employees on the same basis.

Unit Ownership Requirements

We do not currently have any policy or guideline that requires a specified ownership of our units by our directors or executive officers or unit retention guidelines applicable to equity-based awards granted to directors and executive officers. Although we do not have a policy requiring ownership, each of our named executive officers directly or indirectly owns units.

As of December 31, 2006, our named executive officers as a group beneficially own 7,166,336 units and options to acquire 100,000 units. If all options were exercised, our named executive officers would have beneficially owned approximately 39.3% of our issued and outstanding units. See Outstanding Equity Awards at Fiscal 2006 Year-End for outstanding options held by our named executive officers.

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Summary Compensation Table

The following table sets forth the aggregate compensation awarded to, earned by or paid to our named executive officers serving at December 31, 2006.

Name and Principal Position	Year	Salary ($)(1)	Bonus ($)	Unit Awards ($)	Option Awards ($)(2)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings	All Other Compensation ($)	Total ($)
Cary D. Brown *Chairman of the Board, Chief Executive Officer and President*	2006	$ 150,000			$ 9,338				$ 159,338
Steven H. Pruett, *President, Chief Financial Officer and Secretary*	2006	$ 131,250	$ 14,000		$ 9,338			$ 10,305(3)	$ 164,893
Kyle A. McGraw, *Director Executive Vice President of Business Development and Land*	2006	$ 112,500			$ 9,338				$ 121,838
Paul T. Horne, *Vice President of Operations*	2006	$ 112,625	$ 12,000		$ 9,338				$ 133,963
William M. Morris, Vice *President, Chief Accounting Officer and Controller*	2006	$ 111,767	$ 40,000	$ 158,462(4)	$ 9,338			$ 31,478(5)	$ 351,045

(1) Salaries were paid to officers beginning April 1, 2006.

(2) All options granted have an exercise price equal to the market value of the option on the date of grant in accordance with FAS 123(R). The exercise price for these options was determined by our compensation committee based on an approximation of the current value of our units in relation to the price at which our units were (i) sold in our March 2006 private equity offering, (ii) traded on the Portal Market, or (iii) the price to the public of our units sold in the initial public offering. The amount shown is the compensation expense recognized for the year ended December 31, 2006, which is based upon the straight-line amortization of the grant date fair

value.

(3) Reflects value of perquisites we paid for Mr. Pruett s travel to and from our offices in Midland from his residence.

(4) Reflects the 2006 compensation expense recognized based upon the straight-line amortization of the grant date fair value of the 35,077 restricted units granted to Mr. Morris on March 15, 2006 under his employment agreement using the price at which our units were sold in our March 2006 private equity offering.

(5) Reflects the unit distributions received by Mr. Morris on his unvested restricted units.

GRANTS OF PLAN-BASED AWARDS IN FISCAL YEAR 2006

The following table sets forth the payments that may be made under our LTIP.

			Estimated Future Payouts Under Equity Incentive Plan Awards						
Name	**Grant Date**	**Date Action Taken(1)**	**Threshold**	**Target**	**Maximum**	**All Other Unit Awards: Number of Units**	**All Other Option Awards: Number of Securities Underlying Options**	**Exercise or Base Price of Option Awards ($/Unit)**	**Grant Date Fair Value of Unit and Option Awards**
Cary D. Brown	7/17/06	6/29/06					20,000	$ 17.00	$ 52,400
Steven H. Pruett	7/17/06	6/29/06					20,000	$ 17.00	$ 52,400
Kyle A. McGraw	7/17/06	6/29/06					20,000	$ 17.00	$ 52,400
Paul T. Horne	7/17/06	6/29/06					20,000	$ 17.00	$ 52,400
William M. Morris	7/17/06	6/29/06				35,077	20,000	$ 17.00	$ 648,709(2)

(1) Reflects the date on which the compensation committee was deemed to take action in making a grant of unit options.

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(2) Includes the grant date fair value of the 35,077 restricted units granted to Mr. Morris on March 15, 2006 under his employment agreement using the price at which our units were sold in our March 2006 private equity offering.

EMPLOYMENT AGREEMENTS

Through our wholly owned subsidiary Legacy Reserves Services, Inc. we have employment agreements with each of our executive officers. These agreements establish that each of our named executive officers is employed by Legacy Reserves Services, Inc., and provide for the employment of Mr. Brown as Chief Executive Officer, Mr. Pruett as President and Chief Financial Officer, Mr. McGraw as Executive Vice President of Business Development and Land, Mr. Horne as Vice President of Operations and Mr. Morris as Controller of our general partner. Each of these agreements became effective upon the completion of our private placement on March 15, 2006, and is terminable either by the executive or by us at any time.

Base Salaries

The employment agreements provide that Messrs. Brown, Pruett, McGraw, Horne and Morris will receive an annual base salary of $200,000, $175,000, $150,000, $150,000 and $125,000, respectively. The board of directors of our general partner approved an increase in Mr. Morris annual base salary to $150,000 effective May 1, 2006. The agreements provide that each executive officer is entitled to participate in equity and non-equity incentive programs that we may establish from time to time and incentive compensation will be paid at the discretion of the board of directors of our general partner.

Intellectual Property and Non-Compete Clauses

The employment agreements with each of our named executive officers require that the executive officer must promptly disclose and assign any individual rights that he may have in any intellectual property and business opportunities to us. For purposes of the agreement, intellectual property includes inventions, discoveries, processes, designs, methods, substances, articles, computer programs, or improvements and business opportunities include business ideas, prospects, proposals or other opportunities pertaining to the lease, acquisition, exploration, production, gathering or marketing of hydrocarbons and related products and the exploration potential of geographical areas on which hydrocarbon exploration prospects are located. Under the non-compete provisions of these agreements, the executive officers are prohibited from engaging or participating, with any person or entity, in any activity pertaining to the leasing, acquiring, exploring, producing, gathering or marketing of hydrocarbons during the term of the executive officer s employment and the executive officer may not invest in any other such business unless prior approval is granted in writing by our board of directors. The non-compete provisions limit the executives right to engage in these activities for a period of six months after termination of employment in counties where we do business, six months in adjacent counties, and limit investment to $500,000 in publicly traded companies engaged in similar businesses for a period of one year after termination unless such competitive activity is approved in writing by a majority of the independent directors of our general partner s board of directors. The employment agreements also prohibit the executive officer from soliciting any of our employees or customers for two years following termination.

The employment agreements prohibit the executive officers from engaging in or participating in any publicly traded partnership or limited liability company or privately held company contemplating an initial public offering as a limited partnership or a limited liability company that is in direct competition with us for one year following the termination of employment.

The non-compete provisions contained in the employment agreements will not apply to investments by the executive officers made prior to the effective date of their respective employment agreements, provided that the investments were identified in the employment agreement. In addition, the non-compete provisions will not apply if we terminate the executive officer s employment within one year following a change of control.

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Severance and Change in Control Payments

Pursuant to the terms of the employment agreements, we may be obligated to make severance payments to our named executive officers following the termination of their employment. These benefits are described below under Benefits Upon Termination or Change in Control.

In the event that any payments to which any named executive officer is entitled becomes subject to the excise tax imposed by Section 4999 of the Internal Revenue Code, then the board may provide for the payment of, or otherwise reimburse the executive for the amount of the excise tax. Additionally, to the extent any payments to which any named executive officer is entitled is deemed to constitute non-qualified deferred compensation subject to Section 409A of the Internal Revenue Code, the we will have the discretion to adjust the terms of such payment or benefit as we deem necessary to comply with the requirements of Section 409A to avoid the imposition of any excise tax or other penalty with respect to such payment or benefit under Section 409A.

Benefits Payable Upon Termination or Change in Control

The following table presents, for each named executive officer, the potential post employment payments and payments on a change in control as of December 31, 2006. Set forth below the table is a description of certain post-employment arrangements with our named executive officers, including the severance benefits and change in control benefits to which they are entitled under their employment agreements.

Named Executive Officer	Benefit	Before Change in Control w/o Cause or for Good Reason		After Change in Control w/o Cause or for Good Reason	
Cary D. Brown	Severance(a)	$	400,000	$	600,000
	Bonus(b)				
	Benefits(c)	$	22,800	$	34,200
	Unit Options(d)	$	52,400	$	52,400
Steven H. Pruett	Severance(a)	$	350,000	$	525,000
	Bonus(b)	$	28,000	$	42,000
	Benefits(c)	$	22,800	$	34,200
	Unit Options(d)	$	52,400	$	52,400
Kyle A. McGraw	Severance(a)	$	300,000	$	450,000
	Bonus(b)				
	Benefits(c)	$	22,800	$	34,200
	Unit Options(d)	$	52,400	$	52,400
Paul T. Horne	Severance(a)	$	300,000	$	450,000
	Bonus(b)	$	24,000	$	36,000
	Benefits(c)	$	22,800	$	34,200
	Unit Options(d)	$	52,400	$	52,400
William M. Morris	Severance(a)	$	300,000	$	450,000
	Bonus(b)	$	80,000	$	120,000
	Benefits(c)	$	22,800	$	34,200
	Units Options(d)	$	52,400	$	52,400
	Restricted Units(e)	$	666,463	$	666,463

(a) If terminated without cause, or executive terminates with good reason, executive is entitled to an amount equal to two years annual salary, or three years annual salary if termination occurs within one year of a change of control.

(b) Executives are entitled to an average of bonus paid over past two years plus the pro-rata bonus earned in year of termination but unpaid at the time of termination.

(c) Executives are entitled to COBRA benefits for the shorter of the severance period or the time at which executive receives substantially similar benefits from a subsequent employer.

(d) Reflects grant date fair value of the 20,000 unit options granted on July 17, 2006.

(e) Reflects value of restricted units based on the IPO price of $19.00 on January 11, 2007.

Severance Benefits

Under the employment agreements, we may be obligated to make severance payments following the termination of each executive officer s employment if we terminate him without cause or he terminates his employment for good reason, subject to certain cure periods. Cause is defined under each employment agreement as:

the executive officer s conviction of or plea of nolo contendere to any felony or crime or offense causing substantial harm to the partnership, general partner, or its direct or indirect subsidiaries, or involving acts of theft, fraud, embezzlement, moral turpitude or similar conducts;

the executive officer s repeated intoxication by alcohol or drugs during the performance of his duties;

the executive officer s malfeasance in the conduct of executive s duties including, but not limited to, willful and intentional misuse or diversion of any funds, embezzlement or fraudulent or willful an material misrepresentations or concealments on any written reports;

the executive officer s material failure to perform the duties of his employment consistent with his position, expressly including the provisions of the agreements or material failure to follow or comply with the reasonable and lawful written directives of the board;

a material breach of the employment agreement; or

a material breach by the executive officer of written policies of the partnership, the general partner, or any of our direct or indirect subsidiaries.

Each named executive officer will have a fifteen day cure period prior to termination for cause under these agreements.

Good reason is defined under each employment agreement as:

a reduction in the executive officer s base salary;

the relocation of the executive officer s primary place of employment to a location more than twenty miles from Midland, Texas; or

any material reduction in the executive officer s title, authority or responsibilities.

If the employment of any named executive officer is terminated by us for cause or by the executive officer without good reason, we are not obligated to make any severance payments to the executive officer. The amount that an executive officer is entitled to receive upon a termination of his employment by us without cause or by the executive officer with good reason is based on the executive officer s salary and his incentive compensation. Under the severance provisions of each executive officer s employment agreement, they are each entitled to severance pay in the amount of two years of annual base salary payable monthly at the highest rate in effect at any time during the thirty-six month period prior to termination, the average annual bonus of the two years preceding the termination and an amount equal to the executive s pro-rata bonus for the fiscal year in which the termination occurs. In addition, the executive officers are entitled to the full costs of the executive s COBRA continuation coverage for the shorter of the severance period or the time when the executive receives substantially similar benefits from a subsequent employer. In addition, Messrs. Brown and McGraw would have the right to exercise one demand registration right each.

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Change in Control Benefits

Pursuant to the employment agreements, we may be required to make payments to named executive officers upon a change in control, which occurs upon any of the following:

the acquisition by any individual or entity of beneficial ownership of 35% or more of either (i) the then-outstanding equity interests of the partnership or (ii) the combined voting power of the then-outstanding voting securities of the partnership entitled to vote generally in the election of directors. Indirect or direct acquisitions by the partnership, business combinations that do not result in a change of equity ownership with combined voting power of more than 50%, transactions where at least a majority of the members of the board of directors of our general partner of any entity resulting from a business combination were members of the board at the time of the execution of the initial agreement for such a transaction, or any acquisition arising out of or in connection with an initial public offering or private placement of our securities.

where individuals who constitute the board at the time of the agreement cease to constitute at least a majority of the board, unless an individual becoming a director subsequent to the date of the agreement was approved by a vote of at least a majority of the directors then comprising the board, excluding any individual whose election occurs as a result of an actual or threatened election contest;

consummation of a reorganization, merger, statutory share exchange or consolidation or similar corporate transaction involving the partnership or any of its subsidiaries, a sale or other disposition of all assets or equity interests of another entity by the partnership or any of its subsidiaries unless all or substantially all of the individuals and entities that were the beneficial owners of the outstanding equity and voting securities immediately prior to such transaction beneficially own more than 50% of the then-outstanding equity interests and the combined voting power of the then-outstanding voting securities entailed to vote after such business transaction in substantially the same proportions as their ownership immediately prior to such transaction, no person beneficially owns, 35% or more of the entity resulting from such transaction, except to the extent that such ownership existed prior to the transaction, or at least a majority of the members of the board of directors of the corporation or equivalent body of any other entity resulting from such transactions were members of the board at the time of the execution of the initial agreement or of the action of the board providing for such transaction; or

consummation of a complete liquidation or dissolution of the partnership.

If a termination without cause or by the executive officer with good reason occurs within one year following a change in control the executive officer will be entitled to a payment of thirty-six months of his annual base salary determined at the highest rate in effect at any time during the thirty-six month period prior to termination, payable in a lump sum within thirty days. In addition, the executive will be entitled to receive the average annual bonus of the two years preceding the termination, an amount equal to the executive s pro-rata bonus for the fiscal year in which the termination occurs and the full costs of the executive s COBRA continuation coverage for the shorter of the severance period or the time when the executive receives substantially similar benefits from a subsequent employer.

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Outstanding Equity Awards at 2006 Fiscal Year-End

The following table reflects all of the outstanding equity awards held by our named executive officers as of December 31, 2006.

	Option Awards					Unit Awards	
Name	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date	Number of Units That Have Not Vested (#)	Market Value of Units That Have Not Vested ($)
Cary D. Brown		20,000		$ 17.00	July 16, 2011(a)		
Steven H. Pruett		20,000		$ 17.00	July 16, 2011(a)		
Kyle A. McGraw		20,000		$ 17.00	July 16, 2011(a)		
Paul T. Horne		20,000		$ 17.00	July 16, 2011(a)		
William M. Morris		20,000		$ 17.00	July 16, 2011(a)	35,077(b)	$ 666,463(c)

(a) Options vest one-third annually commencing March 15, 2007 and expire five years from the grant date of July 17, 2006.

(b) Includes 35,077 restricted units granted on March 15, 2006 which vest one-third annually commencing March 15, 2007.

(c) Reflects value of restricted units based on the IPO price of $19.00 on January 11, 2007.

Option Exercises and Units Vested in 2006

No options were exercised and no unit awards vested during 2006.

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

The following table sets forth the beneficial ownership of our units as of March 19, 2007.

each person known by us to be a beneficial owner of 5% or more of our outstanding units;

each of the directors of our general partner;

each named executive officer of our general partner; and

all directors and executive officers of our general partner as a group.

The amounts and percentage of units beneficially owned are reported on the basis of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, a person is deemed to be a beneficial owner of a security if that person has or shares Voting power, which includes the power to vote or to direct the voting of such security, or investment power, which includes the power to dispose of or to direct the disposition of such security. A person is also deemed to be a beneficial owner of any securities of which that person has a right to acquire beneficial ownership within 60 days. Under these rules, more than one person may be deemed a beneficial owner of the same securities, and a person may be deemed a beneficial owner of securities as to which he has no economic interest.

Except as indicated by footnote, to our knowledge the persons named in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable. Mr. VanLoh s address is 777 Walker Street, Suite 2530, Houston, Texas 77002, and the business address for the other beneficial owners listed below is 303 W. Wall Street, Suite 1600, Midland, Texas 79701.

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	Units Beneficially Owned	
	Number	Percentage
Name of Beneficial Owner		
Moriah Group(a)(b)	7,289,999	28.7%
Moriah Properties, Ltd.(a)	6,747,718	26.6
Brothers Group(a)(c)	4,189,525	16.5
Brothers Production Properties, Ltd.(a)	3,381,780	13.3
Brothers Production Company, Inc.(a)(d)	3,561,661	14.0
MBN Properties LP	3,162,438	12.5
Newstone Group(a)	1,638,861	6.5
Directors and Officers		
Dale A. Brown(a)(e)(f)	7,291,749	28.8
Cary D. Brown(a)(g)(h)	6,754,398	26.6
Kyle A. McGraw(h)	6,680	*
S. Wil VanLoh, Jr.(a)(e)(i)(j)	917,630	3.8
Kyle D. Vann(e)	1,750	*
William D. Sullivan(e)	1,750	*
G. Larry Lawrence(e)	4,000	*
Steven H. Pruett(a)(h)(i)(k)	303,615	1.2
Paul T. Horne(a)(h)(l)	128,363	*
William M. Morris(h)(m)	18,372	*
All directors and executive officers as a group (10 persons)	8,680,589	34.2

* Percentage of units beneficially owned does not exceed (1%).

(a) Assumes that the units held by MBN Properties LP will be distributed to the partners of MBN Properties LP, including Moriah Properties, Ltd., Brothers Production Properties, Ltd., Brothers Production Company, Inc., the Newstone Group, SHP Capital LP, DAB Resources, Ltd. and H2K Holdings, Ltd. as follows:

Entity	Number
Moriah Properties, Ltd.	884,175
Brothers Production Properties, Ltd.	457,967
Brothers Production Company, Inc.	24,360
Brothers Operating Company, Inc.	4,872
Newstone Group	1,447,157
SHP Capital LP	191,704
DAB Resources, Ltd.	27,330
H2K Holdings, Ltd.	70,944
J&W McGraw Properties, Ltd.	53,929
Total	3,162,438

(b)

Includes units held by Moriah Properties, Ltd. as well as 542,281 units held by DAB Resources, Ltd., assuming that the units held by MBN Properties LP are distributed to partners of MBN Properties LP as described in footnote (a) above.

(c) Includes units held by Brothers Production Properties, Ltd. and Brothers Production Company, Inc. as well as 35,976 units held by Brothers Operating Company, Inc. and 591,887 units held by J&W McGraw Properties, Ltd., assuming that the units held by MBN Properties LP are distributed to partners of MBN Properties LP as described in footnote (a) above.

(d) Brothers Production Company, Inc., in its capacity as general partner of Brothers Production Properties, Ltd. is deemed to beneficially own the partnership interests in us held by Brothers Production Properties, Ltd. as well as 179,882 units it holds directly, assuming that the units held by MBN Properties LP are distributed to partners of MBN Properties LP as described in footnote (a) above.

(e) Includes 1,750 units granted under the Legacy Reserves LP Long-Term Incentive Plan to each non-employee director.

(f) Mr. Dale A. Brown is deemed to beneficially own the partnership interests in us held by Moriah Properties, Ltd. as well as 542,281 units held by DAB Resources, Ltd., assuming that the units held by MBN Properties LP are distributed to partners of MBN Properties LP as described in footnote (a) above. Mr. Dale A. Brown and Mr. Cary D. Brown share voting and investment power with respect to the partnership interests in us held by Moriah Properties, Ltd.

(g) Mr. Cary D. Brown is deemed to beneficially own the partnership interests in us held by Moriah Properties, Ltd. Mr. Dale A. Brown and Mr. Cary D. Brown share voting and investment power with respect to the partnership interests in us held by Moriah Properties, Ltd.

(h) Includes 6,680 units that may be acquired upon the exercise of vested options.

(i) Assumes that the units beneficially owned by the Newstone Group will be distributed to the members of the Newstone Group, including entities controlled by Mr. VanLoh and Mr. Pruett as follows:

Entity	**Number**
Blackstone Investments I, Ltd.	388,458
Blackstone Investments II, Ltd.	142,819
Newstone Capital, LP	239,372
SHP Capital LP	105,231
Trinity Equity Partners I, LP	571,277
Total	1,447,157

(j) Mr. VanLoh is deemed to beneficially own the units held by Newstone Capital, LP, Trinity Equity Partners I, LP and 105,231 units held by SHP Capital, LP, assuming that the units held by MBN Properties LP are distributed to the partners of MBN Properties LP as described in footnote (a) above and that the units beneficially owned by the Newstone Group will be distributed to the members of the Newstone Group as described in footnote (i) above.

(k) Mr. Pruett is deemed to beneficially own the 296,935 units held by SHP Capital L.P., assuming that the units held by MBN Properties LP are distributed to partners of MBN Properties LP as described in footnote (a) above.

(l) Mr. Horne is deemed to beneficially own the 121,683 units held by H2K Holdings, Ltd., assuming that the units held by MBN Properties LP are distributed to partners of MBN Properties LP as described in footnote (a) above.

(m) Includes 11,692 of the 35,077 restricted units Mr. Morris was granted upon the closing of our private equity offering.

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The following table sets forth the beneficial ownership of equity interests of Legacy Reserves GP, LLC

Name of Beneficial Owner	Equity Interest
Dale A. Brown(a)(b)	55.2%
Cary D. Brown(b)(c)	51.0
Kyle A. McGraw	
S. Wil VanLoh, Jr.(d)	6.5
Steven H. Pruett(d)	2.2
Kyle D. Vann	
William D. Sullivan	
G. Larry Lawrence	
Paul T. Horne	0.9
William M. Morris	
All directors and executive officers as a group (10 persons)	64.8

(a) Assumes that the equity interests held by MBN Properties LP will be distributed to the partners of MBN Properties LP, including Moriah Properties, Ltd., Brothers Production Properties, Ltd., Brothers Production Company, Inc. and the Newstone Group.

(b) Includes a 44.5% equity interest held by Moriah Properties, Ltd. and a 4.0% equity interest held by DAB Resources, Ltd.

(c) Includes a 44.5% equity interest held by Moriah Properties, Ltd.

(d) Assumes that the equity interests beneficially owned by the Newstone Group will be distributed to the members of the Newstone Group, including entities controlled by Mr. VanLoh and Mr. Pruett.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information as of December 31, 2006 concerning units that may be issued under the Legacy Reserves LP Long-Term Incentive Plan. For more information about this plan, which did not require approval by our limited partners, please read Note 14 of our Notes to Consolidated Financial Statements and Executive Compensation Long-Term Incentive Plan.

	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants	Weighted-Average Exercise Price of Outstanding Options,	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plan (Excluding Securities

Plan Category	and Rights (a)		Warrants and Rights (b)	Reflected in Column (a)) (c)
Equity compensation plans approved by security holders				
Equity compensation plans not approved by security holders(1)	260,000	$	17.01	1,666,134
Total	260,000	$	17.01	1,666,134

(1) Please read Executive Compensation Long-Term Incentive Plan for a description of the material features of the plan, including the awards that may be granted under the plan.

ITEM 13. ***CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS***

Our Founding Investors including members of our management and directors, own an aggregate of 13,316,184 units, which represents a 52% limited partner interest in us. In addition, our general partner owns an approximate 0.1% general partner interest in us.

Distributions and Payments to Our General Partner and Its Affiliates

The following table summarizes the distributions and payments made or to be made by us to our general partner and our Founding Investors in connection with our formation, ongoing operation and any liquidation of Legacy Reserves LP. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm s-length negotiations.

Distributions of available cash to our general partner and our Founding Investors	We will generally make cash distributions of approximately 99.9% to the unitholders pro rata, including our Founding Investors, as the holders of an aggregate of 13,316,184 units, and approximately 0.1% to our general partner. Assuming we have sufficient available cash to pay the full amount of our current quarterly distribution on all of our outstanding units for four quarters, our general partner would receive an annual distribution of approximately \$30,030 on its approximate 0.1% general partner interest, and our Founding Investors would receive approximately \$21.8 million on their units.
Payments to our general partner	Our general partner will be entitled to reimbursement for all expenses it incurs on our behalf. The partnership agreement provides that our general partner will determine the expenses that are allocable to us in good faith. Please read The Partnership Agreement Reimbursement of Expenses.
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its general partner interest will either be sold to the new general partner for cash or converted into units, for an amount equal to the fair market value of that interest. Please read The Partnership Agreement Withdrawal or Removal of the General Partner.

Distribution Upon Liquidation

Liquidation	Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their respective capital account balances

Agreements Governing the Transactions

We and other partners have entered into the various documents and agreements that effected the private equity offering transactions, including the vesting of assets in, and the assumption of liabilities by, us and our subsidiaries, and the application of the proceeds of the private equity offering. These agreements, including the Omnibus Agreement described below, were not the result of arm s-length negotiations, and they, or any of the transactions that they provide for, may not have been effected on terms at least as favorable to the parties to these agreements as they could have been obtained from unaffiliated third parties. All of the transaction expenses incurred in connection with these transactions, including the expenses associated with transferring assets into our subsidiaries, were paid from the proceeds of the private equity offering.

Omnibus Agreement

On March 15, 2006, we entered into an agreement with our Founding Investors and certain of their affiliates. The agreement, which we refer to as the Omnibus Agreement, set forth the overall agreement of the parties with respect to the formation transactions among the parties and included:

- the contribution of assets by the Founding Investors and the units to be issued in exchange therefore pursuant to a Contribution, Conveyance and Assumption Agreement;

- the granting of registration rights to the Founding Investors pursuant to the Founders Registration Rights Agreement described below;

the agreement of the Founding Investors to vote for two individuals designated by the Moriah Group, one individual designated by the Brothers Group, and one individual designated by the Newstone Group in the election of directors of our general partner prior to the election of the board of directors by our unitholders; and

reimbursement for expenses incurred in connection with our formation.

Founders Registration Rights Agreement

The Founding Investors and their permitted transferees are entitled to registration rights pursuant to the Founders Registration Rights Agreement. The Founders Registration Rights Agreement gives the beneficiaries thereof certain demand and piggyback registration rights pursuant to which they will be entitled to cause us to use our commercially reasonable best efforts to register all or a portion of their units and participate in our registration of securities under the Securities Act.

Transactions with Related Persons

Formation Transactions

Simultaneously with the completion of the private equity offering, each of the Founding Investors contributed oil and natural gas properties and related assets to us, and we purchased oil and natural gas properties from MBN Properties LP and the charitable foundations. In consideration for the oil and natural gas properties and related assets, we paid cash in the aggregate amount of approximately $73.0 million and issued an aggregate of 17,640,068 unregistered units.

The following table sets forth for each of the Founding Investors and the three charitable foundations the cash and units received pursuant to the formation transactions:

	Cash (In millions)	Units
Moriash Group:		
Moriah Properties, Ltd.		7,334,070
DAB Resources, Ltd.		859,703
Brothers Group:		
Brothers Production Properties, Ltd.		4,968,945
Brothers Production Company, Inc.		264,306
Brother Operating Company, Inc.		52,861
J&W McGraw Properties, Ltd.		914,246
MBN Properties LP	$ 65.30	3,162,438
H2K Holdings, Ltd.		83,499
Charities Support Foundation, Inc.	$ 0.21	
Moriah Foundation, Inc.	$ 3.74	
Cary Brown Family Foundation, Inc.	$ 3.74	

We received proceeds of $79.1 million, net of initial purchaser s discount and placement agent s fees, from our private equity offering. With a portion of these proceeds, we redeemed an aggregate of 4,400,000 units for a total consideration of $69.9 million from the following entities, in the following amounts, at a price

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per unit of $15.89, which is equal to the price per unit received by Legacy from the purchasers in the private equity offering net of initial purchaser s discount and placement agent s fee:

Entity	Units Redeemed	Units Owned After Redemption
Moriah Properties, Ltd.	1,470,527	5,863,543
DAB Resources, Ltd.	344,752	514,951
Brothers Production Properties, Ltd.	2,045,133	2,923,812
Brother Production Company, Inc.	108,784	155,522
Brothers Operating Company, Inc.	21,757	31,104
J&W McGraw Properties, Ltd.	376,288	537,958
H2K Holdings, Ltd.	32,759	50,740
Total	4,400,000	10,077,630

In September 2005, MBN Properties LP acquired the PITCO properties for $63.9 million cash ($64.3 million including asset retirement obligations) net of post-closing adjustments. Mr. Cary D. Brown, the Chief Executive Officer and Chairman of the Board of our general partner, Mr. Pruett, the President, Chief Financial Officer and Secretary of our general partner, Mr. Horne, the Vice President-Operations of our general partner, Mr. Dale A. Brown, a member of the board of directors of our general partner, and Mr. VanLoh, a member of the board of our general partner, all indirectly own membership interests in MBN Properties LP.

Petroleum Strategies, Inc.

Neither Moriah Properties, Ltd. nor its general partner, Moriah Resources, Inc., have any employees. All operational personnel performing services with respect to their properties and business were employees of Petroleum Strategies, Inc., a Qualified Intermediary for like kind exchanges owned by Mr. Dale A. Brown and Mr. Cary D. Brown. The personnel and general administrative services were provided to Moriah Properties, Ltd. under an overhead allocation agreement. During 2005, Moriah Properties, Ltd. and Moriah Resources, Inc., paid $838,899 to Petroleum Strategies, Inc. pursuant to this agreement as reimbursement for salaries and other general and administrative expenses. We have no future obligations for personal and general and administrative services to Petroleum Strategies.

Office Leases

TCTB Partners, a limited partnership of which Dale A. Brown, Cary D. Brown and Kyle A. McGraw are limited partners, owns the office building in which the principal offices of the Moriah Group, Brothers Group and Petroleum Strategies are located.

During 2005, the Brothers Group and Moriah Group paid rentals of $46,836 and $35,220, respectively, to TCTB Partners. We assumed the existing leases for 15,000 square feet of office space. The annual rental initially payable to TCTB Partners is $82,056, without respect to property taxes and insurance. We also sublease 1,967 square feet of our space to Petroleum Strategies at the same rate per square foot that we are charged by TCTB Partners.

In August 2006 we entered in to an additional lease, having an initial five year term with a five year renewal option, with TCTB Partners. We will lease an additional 4,000 square feet during the first year, an additional 10,000 square feet during the second and third years and an additional 20,000 square feet during the fourth and fifth years at a rate of

$7.00 per square foot, before property taxes and insurance.

Other

Travis McGraw, the brother of Kyle A. McGraw, Executive Vice-President of Business Development and Land and a member of the board of directors of our general partner, is an employee of Legacy serving as our Marketing, Revenue, and Regulatory Reporting Coordinator. We paid Travis McGraw $75,000 as compensation for his services during the year ended December 31, 2006. Travis McGraw s current annual salary is $93,878

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plus a discretionary, non-guaranteed bonus. Additionally, during the year ended December 31, 2006, we hired Scott McGraw, also the brother of Kyle McGraw, as an independent contractor to perform engineering services. We paid Scott McGraw $38,054 during this time as compensation for his services and expects to pay him an additional $15,000 per quarter for his contract engineering services.

In order to fund the purchase price and expenses of the PITCO acquisition, MBN Properties LP and MBN Management, LLC borrowed amounts from entities owned and controlled by certain of our officers and directors.

On July 21, 2005, MBN Properties LP entered into a $6.5 million subordinated loan agreement under which Moriah Properties, Ltd., an entity owned and controlled by Cary D. Brown and Dale A. Brown, contributed $1,648,670, Brothers Production Properties, Ltd., an entity owned a controlled by Kyle A. McGraw, the Executive Vice President of Business Development and Land and member of the board of directors of our general partner, contributed $1,176,330, Newstone Capital, LP and Trinity Equity Partners I, LP, entities owned and controlled by Mr. VanLoh, contributed $65,000 and $186,250, respectively, and SHP Capital LP, an entity owned and controlled by Mr. Pruett, contributed $62,500. The $3,325,000 borrowed under the subordinated loan agreement was used to fund the deposit for the purchase of the PITCO properties.

On July 22, 2005, MBN Management, LLC entered into a $2 million subordinated loan agreement under which Brothers Production Properties, Ltd. contributed $619,888, Moriah Properties, Ltd. contributed $900,112, Newstone Capital, LP contributed $50,801, Trinity Equity Partners I, LP contributed $141,550 and SHP Capital LP contributed $46,099. MBN Management, LLC borrowed approximately $1.9 million under the subordinated loan agreement to fund expenses related to the PITCO acquisition.

On September 13, 2005, MBN Properties LP replaced the $6.5 million subordinated loan agreement by entering into a $34 million subordinated loan agreement under which Moriah Properties, Ltd. contributed an additional $17,861,990 and Brothers Production Properties, Ltd. contributed $12,588,030. MBN Properties LP borrowed approximately $33.8 million under the subordinated loan agreement to partially fund the remaining purchase price of the PITCO properties.

All amounts outstanding under the $2 million and $34 million subordinated loan agreements were repaid in full on March 15, 2006 with proceeds from our private equity offering and borrowings under our $300 million revolving credit facility that we entered into at the closing of our private equity offering.

On October 23, 2003, Moriah Resources, Inc. purchased from Pecos Production Company a working interest in the Langlie Mattix Penrose Sand Unit located in Lea Country, New Mexico for approximately $2.1 million. On November 19, 2003, Paul T. Horne, our Vice President of Operations, purchased from Moriah Resources, Inc. a working interest in the Langlie Mattix Penrose Sand Unit. As part of the transaction, Mr. Horne received a 5% back-in-after-payout from Moriah Resources, Inc. In December 2005, Moriah Resources, Inc. purchased the 5% back-in-after-payout from Mr. Horne for approximately $331,040.

Director Independence

Please read Item 10 Directors and Executive Officers and Corporate Governance Director Independence above for information about the independence of our general partners board of directors and its committees, which information is incorporated herein by reference.

ITEM 14. *PRINCIPAL ACCOUNTANT FEES AND SERVICES*

The Audit Committee had not, as of the time of filing this annual report on Form 10-K with the Securities and Exchange Commission, adopted policies and procedures for pre-approving audit or permissible non-audit services performed by our independent auditors. Instead, the Audit Committee as a whole has pre-approved all such services. In the future, our Audit Committee may approve the services of our independent auditors pursuant to pre-approval policies and procedures adopted by the Audit Committee, provided the policies and procedures are detailed as to the particular service, the Audit Committee is informed of each service, and such policies and procedures do not include delegation of the Audit Committee s responsibilities to our management.

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The aggregate fees for professional services rendered by our principal accountants, BDO Seidman, LLP, for 2005 and 2006 were:

	Year Ended December 31, 2005	Year Ended December 31, 2006
Audit fees	$ 461,180	$ 668,442
Audit-related fees		98,436
Tax fees		
All other fees		
Total	$ 461,180	$ 766,878

In the above table, audit fees are fees we paid for professional services for the audit of our Consolidated Financial Statements included in our annual report on Form 10-K or for services that are normally provided by our principal accountants in connection with statutory and regulatory filings or engagements and fees for Sarbanes-Oxley 404 audit work. Audit-related fees are fees billed for assurance and related services in connection with acquisition transactions and related regulatory filings. The fees shown in the table above represent services rendered to Legacy Reserves LP subsequent to the Formation Transaction on March 15, 2006. Fees for services to the Moriah Group, the Brothers Group or H2K Holdings are not included in the table above since such services were rendered prior to the Legacy Formation on March 15, 2006.

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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 Reserve LP s Registration Statement on Form S-1 (File No. 33-134056) filed May 12, 2006, included as Appendix A to the Prospectus and including specimen unit certificate for the units)
3.3	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)
3.4	Amended and Restated Limited Liability Company Agreement 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 3.4)
4.1	Registration Rights Agreement dated as of March 15, 2006 by and among Legacy Reserves LP, Legacy Reserves GP, LLC and Friedman, Billings, Ramsey & Co. (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 4.1)
4.2	Registration Rights Agreement dated June 29, 2006 between Henry Holding LP and Legacy Reserves LP and Legacy Reserves GP, LLC (the Henry Registration Rights Agreement) (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006 Exhibit 4.2)
4.3	Registration Rights Agreement dated March 15, 2006 by and among Legacy Reserves LP, Legacy Reserves GP, LLC and the other parties thereto (the Founders Registration Rights Agreement) (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006 Exhibit 4.3)
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 LP s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.1)
10.2	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 LP s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.2)
10.3	Omnibus 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 LP s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.3)
10.4	Purchase/Placement Agreement dated as of March 6, 2006 by and among Legacy Reserves LP, Legacy Reserves GP, LLC and the other parties thereto (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.4)

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Exhibit Number	Description
10.5	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)
10.6	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)
10.7	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)
10.8	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)
10.9	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)
10.10	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)
10.11	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)
10.12	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)
10.13	Employment Agreement dated as of March 15, 2006 between William M. Morris 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 10.13)
10.14	First Amendment to Credit Agreement effective as of July 7, 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 LP s Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006, Exhibit 10.14)
10.15	Purchase and Sale Agreement dated June 29, 2006 between Kinder Morgan Production Company LP and Legacy Reserves Operating LP (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed October 5, 2006, Exhibit 10.15)
10.16	Purchase and Sale Agreement dated June 13, 2006 between Henry Holding LP and Legacy Reserves Operating LP (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006, Exhibit 10.16)
10.17	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)
21.1	List of subsidiaries 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 21.1)
23.1*	Consent of LaRoche Petroleum Consultants, Ltd.
31.1*	Rule 13a-14(a) Certifications (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

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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, in the City of Midland, State of Texas, on the 28th day of March 2007.

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)

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	Chief Executive Officer and Director (Principal Executive Officer)	March 28, 2007
Cary D. Brown		
/s/ Steven H. Pruett	President, Chief Financial Officer and Secretary (Principal Financial Officer)	March 28, 2007
Steven H. Pruett		
/s/ William M. Morris	Vice President, Chief Accounting Officer and Controller (Principal Accounting Officer)	March 28, 2007
William M. Morris		
/s/ Kyle A. McGraw	Executive Vice President and Director	March 28, 2007
Kyle A. McGraw		
/s/ William D. Sullivan	Director	March 28, 2007
William D. Sullivan		
/s/ Wil VanLoh, Jr.	Director	March 28, 2007

S. Wil VanLoh, Jr.

/s/ Kyle D. Vann	Director	March 28, 2007
Kyle D. Vann		

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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 (formerly the Moriah Group), as defined in Note 1 (a), as of December 31, 2005 and 2006 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, 2006. These financial statements are the responsibility of the Partnership s 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. The Partnership is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits 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, 2005 and 2006 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

/s/ BDO SEIDMAN, LLP

Houston, Texas
March 26, 2007

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LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2005 AND 2006

	2005	2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,954,923	$ 1,061,852
Accounts receivable, net:		
Oil and natural gas	6,051,802	7,599,915
Joint interest owners	113,837	4,345,334
Affiliated entities and other (Notes 3 and 6)	103,850	21,336
Fair value of oil and natural gas swaps (Note 9)	46,675	5,102,083
Prepaid expenses and other current assets		90,609
Total current assets	8,271,087	18,221,129
Oil and natural gas properties, at cost:		
Proved oil and natural gas properties, using the successful efforts method of accounting (Note 15):	85,363,482	289,518,708
Unproved properties	2,928	68,275
Accumulated depletion, depreciation and amortization	(8,194,385)	(42,006,485)
	77,172,025	247,580,498
Other property and equipment, net of accumulated depreciation and amortization of $0 and $51,108, respectively	4,198	303,750
Subordinated notes receivable (Note 5)	304,312	
Operating rights, net of amortization of $0 and $295,314, respectively (Note 1(k))		6,721,358
Other assets, net of amortization of $20,674 and $167,179, respectively	1,190,569	541,743
	$ 86,942,191	$ 273,368,478
LIABILITIES AND UNITHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 451,652	$ 2,931,627
Accrued oil and natural gas liabilities	3,174,752	5,881,612
Due to affiliates (Note 5)	194,907	
Fair value of oil and natural gas swaps (Note 9)	199,624	
Asset retirement obligation (Note 12)	175,944	553,579
Other	365,326	1,466,693
Total current liabilities	4,562,205	10,833,511
Long-term debt (Note 3)	52,473,000	115,800,000
Asset retirement obligation (Note 12)	2,126,203	5,939,201

Fair value of oil and natural gas swaps (Note 9)	3,155,054	2,006,547
Subordinated notes payable partners (Note 5)	14,716,791	
Total liabilities	77,033,253	134,579,259
Commitments and contingencies (Note 7)		
Unitholders equity:		
Limited partners equity 9,488,921 and 18,395,233 units issued and outstanding at December 31, 2005 and 2006, respectively	9,899,029	138,653,452
General partners equity (approximately 0.1%)	9,909	135,767
Total unitholders equity	9,908,938	138,789,219
	$ 86,942,191	$ 273,368,478

See accompanying notes to consolidated financial statements.

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LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2004, 2005 AND 2006

	2004	2005	2006
Revenues:			
Oil sales	$ 10,997,515	$ 18,225,457	$ 45,351,122
Natural gas sales	3,945,400	7,317,744	14,446,193
Realized and unrealized gain (loss) on oil and natural gas swaps (Note 9)	(632,783)	(6,158,865)	9,288,470
Total revenues	14,310,132	19,384,336	69,085,785
Expenses:			
Oil and natural gas production	4,345,249	6,375,613	15,938,276
Production and other taxes	927,657	1,635,530	3,745,793
General and administrative	731,200	1,354,213	3,691,018
Dry hole costs	822		
Depletion, depreciation, amortization and accretion	883,457	2,291,013	18,394,674
Impairment of long-lived assets			16,113,300
Loss on sale of assets		20,523	42,370
Total expenses	6,888,385	11,676,892	57,925,431
Operating income	7,421,747	7,707,444	11,160,354
Other income (expense):			
Interest income	419,257	185,308	129,712
Interest expense (Note 3)	(213,711)	(1,584,408)	(6,644,721)
Gain on sale of partnership investment	1,292,169		
Equity in income (loss) of partnerships (Note 5)	183,474	(495,295)	(317,788)
Other	91,483	45,321	29,328
Income before non-controlling interest	9,194,419	5,858,370	4,356,885
Non-controlling interest		538	
Income from continuing operations	9,194,419	5,858,908	4,356,885
Discontinued operations (Note 10)			
Income from operations	14,981		
Gain on disposal	7,165		
Income from discontinued operations	22,146		
Net income	$ 9,216,565	$ 5,858,908	$ 4,356,885
Earnings per unit basic and diluted (Note 13)			
Income from continuing operations	$ 0.97	$ 0.62	$ 0.26

Income from discontinued operations	$		$		$	
Net income	$	0.97	$	0.62	$	0.26

See accompanying notes to consolidated financial statements.

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LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

CONSOLIDATED STATEMENT OF UNITHOLDERS EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2004, 2005 AND 2006

	Number of Common Units	General Partner	Limited Partner	Total Partners Capital
Balance, December 31, 2003	9,488,921	$ 7,277	$ 7,271,067	$ 7,278,344
Capital contributions		60	59,467	59,527
Distributions to partners		(4,532)	(4,527,665)	(4,532,197)
Net income		9,217	9,207,348	9,216,565
Balance, December 31, 2004	9,488,921	12,022	12,010,217	12,022,239
Capital contributions		144	143,546	143,690
Deemed capital contribution		155	154,994	155,149
Distributions to partners		(8,271)	(8,262,777)	(8,271,048)
Net income		5,859	5,853,049	5,858,908
Balance, December 31, 2005	9,488,921	9,909	9,899,029	9,908,938
Capital contributions		19	19,337	19,356
Net distributions to owners		(2,297)	(2,294,617)	(2,296,914)
Deemed dividend to Moriah Group owners		(3,878)	(3,874,337)	(3,878,215)
Net proceeds from private equity offering	5,000,000	76,784	76,706,734	76,783,518
Redemption of Founding Investors units	(4,400,000)	(69,938)	(69,868,062)	(69,938,000)
Units issued to MBN Properties LP in exchange for the non-controlling interests share of oil and natural gas properties	1,867,290	31,744	31,712,190	31,743,934
Units issued to the Brothers Group in exchange for oil and natural gas properties and other assets	6,200,358	105,406	105,300,663	105,406,069
Units issued to the H2K Holdings Ltd. in exchange for oil and natural gas properties	83,499	1,419	1,418,064	1,419,483
Dividend reimbursement of offering costs paid by MBN Management LLC		(1,200)	(1,199,029)	(1,200,229)
Units issued to Henry Holding LP in exchange for oil and natural gas properties	146,415		2,489,055	2,489,055
Units issued to Legacy Board of Directors for services	8,750		148,750	148,750
Compensation expense on unit options granted to employees			115,316	115,316
Compensation expense on restricted unit awards issued to employees			270,039	270,039
Distributions to unitholders, $0.8974 per unit		(16,558)	(16,542,208)	(16,558,766)
Net income		4,357	4,352,528	4,356,885
Balance, December 31, 2006	18,395,233	$ 135,767	$ 138,653,452	$ 138,789,219

See accompanying notes to consolidated financial statements.

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LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2004, 2005 AND 2006

	2004	2005	2006
Cash flows from operating activities:			
Net income	$ 9,216,565	$ 5,858,908	$ 4,356,885
Adjustments to reconcile net income to net cash provided by operating activities:			
Dry hole costs	822		
Depletion, depreciation, amortization and accretion	883,457	2,291,013	18,394,674
Amortization of debt issuance costs		93,776	360,847
Impairment of long-lived assets			16,113,300
(Gain) loss on oil and natural gas swaps	558,953	6,158,865	(9,288,470)
(Gain) loss on sale of assets	(1,299,334)	20,523	42,370
Equity in (income) loss of partnership	(183,474)	495,295	317,788
Accrued interest on subordinated notes payable partners		817,757	
Accrued interest on subordinated notes receivable partners		(24,797)	
Distributions from oil and gas partnership	103,950		
Non-controlling interest		(538)	
Amortization of unit-based compensation			534,105
Changes in assets and liabilities			
Increase in accounts receivable, oil and natural gas	(762,905)	(3,412,162)	(5,796,270)
(Increase) decrease in accounts receivable, joint interest owners	505,826	605,072	(4,481,124)
Increase in accounts receivable, other	(30,270)	(91,329)	(457,454)
(Increase) decrease in other assets	7,636	(87,887)	(565,329)
Increase (decrease) in accounts payable	(267,960)	395,428	2,693,916
Increase (decrease) in accrued oil and natural gas liabilities	(147,197)	1,107,021	4,227,569
Increase in due to affiliates		194,907	1,059,308
Increase (decrease) in other liabilities		(13,200)	2,078,165
Total adjustments	(630,496)	8,549,744	24,803,491
Net cash provided by operating activities	8,586,069	14,408,652	29,590,280
Cash flows from investing activities:			
Investment in oil and natural gas properties	(3,325,151)	(66,910,315)	(55,907,581)
Investment in other equipment		(4,198)	(243,384)
Investment in operating rights			(7,016,672)
Proceeds from sale of assets	2,003,052		
Investment in notes receivable	(3,330,000)	(899,574)	
Collection of notes receivable	5,675,345	2,380,000	924,441
Net cash settlements on oil and natural gas swaps		(3,530,651)	(262,222)
Net cash provided by (used in) investing activities	1,023,246	(68,964,738)	(62,505,418)

Cash flows from financing activities:			
Proceeds from long-term debt	12,808,708	56,573,000	121,800,000
Payments of long-term debt	(17,293,708)	(6,100,000)	(73,189,791)
Payments of debt issuance costs		(867,756)	(292,803)
Proceeds from subordinated notes payable partners		14,264,360	
Proceeds from issuance of units, net			76,783,518
Redemption of Founding Investors units			(69,938,000)
Dividend reimbursement of offering costs paid by MBN Management LLC			(1,200,229)
Capital contributed by owner	59,527	143,690	19,356
Cash not acquired in Legacy formation transactions			(3,104,304)
Distributions of capital	(4,532,197)	(8,271,048)	(18,855,680)
Net cash provided by (used in) financing activities	(8,957,670)	55,742,246	32,022,067
Net increase (decrease) in cash and cash equivalents	651,645	1,186,160	(893,071)
Cash and cash equivalents, beginning of period	117,118	768,763	1,954,923
Cash and cash equivalents, end of period	$ 768,763	$ 1,954,923	$ 1,061,852

See accompanying notes to consolidated financial statements.

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LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2004, 2005 AND 2006

	2004	2005	2006
Non-Cash Investing and Financing Activities:			
Asset retirement obligation costs and liabilities	$ (41,081)	$ 11,816	$ 2,272,590
Asset retirement obligations associated with property acquisitions	$	$ 445,169	$ 1,888,954
Contributed offering costs	$	$ 155,149	$
Non-controlling interests share of net financing costs of MBN Properties LP capitalized to oil and natural gas properties	$	$	$ 164,202
Units issued to MBN Properties LP in exchange for the non-controlling interests share of oil and natural gas properties	$	$	$ 31,743,934
Units issued to Brothers Group in exchange for:			
Oil and natural gas properties	$	$	$ 105,298,794
Other property and equipment	$	$	$ 107,275
Units issued to H2K Holdings Ltd. in exchange for oil and natural gas properties	$	$	$ 1,419,483
Oil and natural gas hedge liabilities assumed from the Brothers Group and H2K Holdings Ltd.	$	$	$ 3,147,152
Units issued to Henry Holdings LP in exchange for oil and natural gas properties	$	$	$ 2,489,055
Deemed dividend to Moriah Group owners for accounts not acquired in Legacy formation transaction:			
Accounts receivable, oil and natural gas	$	$	$ 4,248,157
Accounts receivable, joint interest owners	$	$	$ 249,627
Accounts receivable, other	$	$	$ 539,968
Other assets	$	$	$ 891,300
Accounts payable	$	$	$ (213,941)
Accrued oil and natural gas liabilities	$	$	$ (1,520,709)

Due to affiliates	$	$	$	(1,254,215)
Other liabilities	$	$	$	(2,166,276)

See accompanying notes to consolidated financial statements.

LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

NOTES TO 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 or Legacy), 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.

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LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

NOTES TO FINANCIAL STATEMENTS (Continued)

MRI was organized as a sub-chapter S corporation on September 28, 1992 under the laws of the State of Texas, and serves as the 1% general partner to MPL. MPL was organized as a limited partnership on July 1, 1999 under the laws of the State of Texas. Dale A. Brown, an individual, has owned oil and natural gas working interests since 1981. Dale A. Brown, who along with his son, Cary D. Brown, are the sole owners of MRI and MPL. The assets of Moriah Properties New Mexico, Ltd. (MNM), a limited partnership organized under the laws of the State of Texas on October 17, 2003, were assigned into MPL effective September 1, 2005, in order to streamline the business of the limited partnerships with identical ownership and a shared general partner, MRI, and the accounts of MNM have been reflected retroactively in the financial statements of MPL. Effective October 1, 2005, Dale and Rita Brown assigned the selected oil and natural gas properties included in these consolidated financial statements to DAB Resources, Ltd., a Texas limited partnership they own.

On July 22, 2005, MPL advanced $1,649,132 in the form of 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 11).

(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 undeveloped 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

LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

NOTES TO FINANCIAL STATEMENTS (Continued)

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 Legacy s independent petroleum engineer, LaRoche Petroleum Consultants, Ltd., and are subject to future revisions based on availability of additional information. Legacy s 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 13, 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 Legacy s 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 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 assesses impairment of capitalized costs of proved oil and natural gas properties by comparing net capitalized costs to estimated undiscounted future net cash flows using oil and natural gas prices as of the last day of the statement period held constant. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, which would consider estimated future discounted cash flows. As of December 31, 2004 and 2005, the estimated undiscounted future cash flows for Legacy s proved oil and natural gas properties exceeded the net capitalized costs, and no impairment was required to be recognized. 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 utilizing 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

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LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

NOTES TO FINANCIAL STATEMENTS (Continued)

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

No provision for income taxes is made in Legacy s consolidated financial statements because the taxable income or loss of Legacy is included in the income tax returns of the individual owners. The net difference between the tax basis of Legacy s assets and liabilities and the reported amounts of Legacy s assets and liabilities is approximately $83.7 million with Legacy s tax basis being the lower amount.

(g) Derivative Instruments and Hedging Activities

Legacy periodically 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. 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. Therefore, the mark-to-market of these instruments is recorded in current earnings (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 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

LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

NOTES TO FINANCIAL STATEMENTS (Continued)

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, 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, 2004, 2005 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, will be amortized over their estimated economic life of approximately 15 years beginning July 1, 2006. Amortization expense will be 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 2007, 2008, 2009, 2010 and 2011 is $588,000, $547,000, $537,000, $522,000 and $510,000, respectively.

(l) Environmental

Legacy is subject to extensive federal, state and local environmental laws and regulations. These laws, which are constantly 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 noncapital 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 are fixed and readily determinable.

(m) Earnings Per Unit

Legacy computes its earnings per unit in accordance with SFAS No. 128, E*arnings per Share*, which requires the presentation of basic and diluted earnings per unit on the face of the income statement. Basic earnings per unit amounts are calculated using the average number of units outstanding during each period. Diluted earnings per unit also gives effect to restricted units and unit options (calculated based upon the treasury stock method).

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LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

NOTES TO FINANCIAL STATEMENTS (Continued)

Basic and diluted earnings per unit for the years ended December 31, 2004 and 2005 were computed based on the 9,488,921 units issued to the Moriah Group on March 15, 2006 in exchange for oil and natural gas properties contributed by it (including its indirect interest in oil and natural gas properties contributed by MBN Properties, LP) in conjunction with the closing of the Legacy Formation on the same date.

(n) Redemption of Units

Units redeemed are recorded at cost.

(o) Segment Reporting

Legacy operates as one business segment within the Permian Basin region. Upon the closing of the PITCO Acquisition on September 14, 2005, the acquisition of the oil and natural gas properties of the Brothers Group, H2K Holdings Ltd. and the Charitable Support Foundations, Inc. and its affiliates on March 15, 2006, the June 29, 2006 acquisition of oil and natural gas properties in the South Justice Unit from Henry Holding LP, the June 29, 2006 acquisition of oil and natural gas properties in the Farmer Field from Larron Oil Corporation and the July 31, 2006 acquisition of certain oil and natural gas properties from Kinder Morgan, operating segments were created for each group of oil and natural gas properties. 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. This statement 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 for the award. Since Legacy had no restricted or option unit awards prior to March 15, 2006, there were no adoption or transition consequences as contemplated by SFAS No. 123(R). Pursuant to the provisions of SFAS 123(R), Legacy s issued units, as reflected in the accompanying consolidated balance sheet at December 31, 2006 does not include 65,116 units related to unvested restricted unit awards.

(q) Recently Issued Accounting pronouncements

In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109.* Interpretation No. 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes.* This Interpretation is effective for fiscal years beginning after December 15, 2006, and Legacy will adopt it in the first quarter of 2007. Legacy does not expect the adoption of Interpretation No. 48 to have a material impact on its financial statements and related disclosures.

In September 2006, the Securities and Exchange Commission (SEC) issued Staff Accounting Bulletin No. 108 (SAB 108). Due to diversity in practice among registrants, SAB 108 expresses SEC staff views regarding the process by which misstatements in financial statements are evaluated for purposes of determining whether financial statement restatement is necessary. SAB 108 is effective for fiscal years ending after November 15, 2006. The adoption of SAB 108 did not have a material impact on Legacy s financial position or results of operations.

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 generally accepted account principles and expands disclosure related to the use of fair value measures in financial statements. The Statement is to be effective for

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LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

NOTES TO FINANCIAL STATEMENTS (Continued)

Legacy s financial statements issued in 2008; however, earlier application is encouraged. The Statement will affect fair value measurements we make after adoption. Legacy is currently evaluating the timing of adoption.

In February 2007, the FASB issued Statement of Financial Accounting Standards No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115.* Statement No. 159 permits entities to choose to measure certain financial instruments and other items at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. Unrealized gains and losses on any items for which Legacy elects the fair value measurement option would be reported in earnings. Statement No. 159 is effective for fiscal years beginning after November 15, 2007. However, early adoption is permitted for fiscal years beginning on or before November 15, 2007, provided Legacy also elects to apply the provisions of Statement No. 157, *Fair Value Measurements*, at the same time. Legacy is currently assessing the effect, if any, the adoption of Statement No. 159 will have on its financial statements and related disclosures.

(2) Fair Values of Financial Instruments

The estimated fair values of Legacy s 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.

Notes receivable. The carrying amounts approximate fair value due to the comparability of the interest rate to market interest rates for instruments of similar terms and credit quality.

Debt. The carrying amount of the revolving long-term debt approximates fair value because Legacy s 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. It represents 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.

(3) Credit Facility

On July 29, 1999, the Moriah Group entered into a Credit Facility (the Agreement) that permitted borrowings up to the lesser of (i) the borrowing base, or (ii) $20 million. The borrowing base was originally set at $8 million, was re-determined annually by the lender and decreased monthly based upon a schedule determined by the terms of the Agreement. Borrowings under the Agreement bore interest at a rate equal to the three-month LIBOR plus an add-on rate which increased from a minimum of 2.0% to a maximum of 3.5% based upon the amount borrowed as a percentage of the borrowing base with the interest payable monthly. The Agreement was secured by substantially all the oil and natural gas assets of the Moriah Group. The Moriah Group had $7.2 million available on the borrowing base and had $2.0 million outstanding at a rate of 4.1% as of December 31, 2004. The Moriah Group paid interest expense on this debt of $239,324 and $18,323 for the years ended December 31, 2004 and 2005, respectively.

On September 13, 2005, the Moriah Group replaced its Credit Agreement with a new Senior Credit Facility (the New Facility) with a new lending group that permitted borrowings in the lesser amount of (i) the borrowing base, or (ii) $75 million. The borrowing base under the New Facility, initially set at $40 million, was subject to re-determination every six months and was subject to adjustment based upon changes in the fair market value of the Moriah Group s oil and natural gas assets. Interest on the New Facility was payable

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LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

NOTES TO FINANCIAL STATEMENTS (Continued)

monthly and was charged in accordance with the Moriah Group s selection of a LIBOR rate plus 1.5% to 2.0%, or prime rate up to prime rate plus 0.5%, dependent on the percentage of the borrowing base which was drawn. Borrowings under this New Facility were due in September 2009. The New Facility contained certain loan covenants requiring minimum financial ratio coverages, involving the current ratio and EBITDA to interest expense. On September 13, 2005, the Moriah Group borrowed $22,123,000 from the new lending group to provide for general corporate purposes, to fund a $4.2 million distribution to Cary Brown and Dale Brown and to advance additional subordinated notes receivable in the amount of $17,598,000 to MBN Properties LP, which purchased oil and natural gas producing properties from PITCO. The Moriah Group s interest rate at December 31, 2005 was 6.0%. The Moriah Group paid interest expense on this debt of $220,638 for the year ended December 31, 2005 and $264,062 for the period from January 1, 2006 through March 15, 2006. At December 31, 2005, the Moriah Group was in compliance with all aspects of the Agreement. All amounts outstanding under this agreement at March 15, 2006 were repaid in full on that date as part of the formation transactions.

On September 13, 2005, MBN Properties LP entered into a Credit Agreement with a new Senior Credit Facility (the MBN Facility) with a lending group that permitted borrowings in the lesser amount of (i) the borrowing base, or (ii) $75 million. The borrowing base under the MBN Facility, initially set at $35 million, was subject to re-determination every six months and was subject to adjustment based upon changes in the fair market value of the MBN Properties LP s oil and natural gas assets. Interest on the MBN Facility was payable monthly and was charged in accordance with MBN Properties LP s selection of a LIBOR rate plus 1.5% to 2.0%, or prime rate up to prime rate plus 0.50%, dependent on the percentage of the borrowing base which was drawn. Borrowings under this MBN Facility were due in September 2007. The MBN Facility contained certain loan covenants requiring minimum financial ratio coverages, involving the current ratio and EBITDA to interest expense. On September 13, 2005, MBN Properties LP borrowed $33,750,000 from the new lending group to purchase oil and natural gas producing properties from PITCO. The MBN Properties LP s interest rate at December 31, 2005 was 6.33%. MBN Properties LP paid interest expense of $431,085 on this debt for the period from inception to December 31, 2005 and $1,300,727 for the period from January 1, 2006 through March 15, 2006. At December 31, 2005, MBN Properties LP was in compliance with all aspects of the Agreement. All amounts outstanding under this agreement at March 15, 2006 were repaid in full on that date as part of the formation transactions.

As an integral part of the Legacy Formation, Legacy entered into a new credit agreement with a new senior credit facility (the Legacy Facility) with the same lending group that participated in the New Facility of the Moriah Group. Legacy s oil and natural gas properties are pledged as collateral for any borrowings under the Legacy Facility. The terms of the Legacy Facility permits borrowings in the lesser amount of (i) the borrowing base, or (ii) $300 million. The borrowing base under the Legacy Facility, initially set at $130 million, is re-determined every six months and will be adjusted based upon changes in the fair market value of the Partnership s oil and natural gas assets. Interest on the Legacy Facility is payable monthly and is charged in accordance with the Partnership s selection of a LIBOR rate plus 1.25% to 1.875%, or prime rate up to prime rate plus 0.375%, dependent on the percentage of the borrowing base which is drawn. On March 15, 2006, Legacy borrowed $65.8 million from the new lending group as part of the Legacy Formation. On October 16, 2006, Legacy s bank group reaffirmed its $130 million borrowing base. As of December 31, 2006, Legacy had outstanding borrowings of $115.8 million at an interest rate of 7.29%. Thus, Legacy had approximately $14.2 million of availability remaining. For the period from March 15, 2006 through December 31, 2006, Legacy paid $5,022,416 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. At December 31, 2006, Legacy was in compliance with all aspects of the Legacy Facility.

LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

NOTES TO FINANCIAL STATEMENTS (Continued)

Long-term debt consists of the following at December 31, 2005 and 2006:

	December 31, 2005	December 31, 2006
MPL - due September 2009	$ 20,723,000	$
MBN Properties LP - due September 2007	31,750,000	
Legacy - due March 2010		115,800,000
	$ 52,473,000	$ 115,800,000

(4) Acquisitions

Denton Devonian Acquisition

Effective April 1, 2004, Moriah Properties, Ltd. acquired from Fasken Oil and Ranch an additional working interest in the JM Denton lease for approximately $580,000. This property is operated by Brothers Production, Inc. Also acquired were working interests in a Fasken operated lease for approximately $1.1 million. Both of these leases are located in the Denton Devonian field in Lea County, New Mexico. The acquisition was funded with cash.

PITCO Acquisition

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 estimated to be approximately $2.8 million. The all cash acquisition was funded from borrowings of $33,750,000 under MBN Properties LP s existing credit facility and from loans from MPL and the Brothers Group (see Note 5). Including direct expenses associated with the PITCO acquisition, MBN Properties LP has recorded a purchase price of approximately $63.9 million, all of which has been allocated to the oil and natural gas properties purchased. In addition, MBN Properties LP has recorded a $445,000 asset retirement obligation (ARO) and related ARO asset under the guidelines of FAS 143. The results of operations from the properties acquired in the PITCO acquisition have been included in Legacy s statements of operations beginning September 14, 2005.

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

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LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

NOTES TO FINANCIAL STATEMENTS (Continued)

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 (Note 14).

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)
		$ 119,015,524

Total purchase price allocated to oil and natural gas properties acquired

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 Group s 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

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LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

NOTES TO FINANCIAL STATEMENTS (Continued)

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 Group s share of MBN Management LLC losses from inception through March 14, 2006		780,239
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 Legacy s statement of operations for the year ended December 31, 2006.

LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

NOTES TO FINANCIAL STATEMENTS (Continued)

South Justis Unit Acquisition

On June 29, 2006, Legacy purchased Henry Holding LP s 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 Legacy s 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 Legacy s 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 Legacy s statement of operations for the year ended December 31, 2006.

Pro Forma Operating Results

The following table reflects the unaudited pro forma results of operations as though the PITCO acquisition had occurred on January 1, 2004 and 2005 and the Formation Transactions and the Farmer Field, South Justis Unit and Kinder Morgan acquisitions had each occurred on January 1, 2005 and 2006. The pro forma amounts are not necessarily indicative of the results that may be reported in the future:

	December 31,		
	2004	2005	2006
	(In thousands)		
Revenues, excluding hedging gains and losses	$ 27,776	$ 64,128	$ 69,884
Revenues, net of hedging gains and losses	$ 27,143	$ 53,080	$ 77,868
Income from continuing operations	$ 8,606	$ 6,295	$ 4,899

Net income	$	8,628	$	6,295	$	4,899
Earnings per unit basic and diluted:						
Income from continuing operations	$	0.91	$	0.34	$	0.27
Net income	$	0.91	$	0.34	$	0.27
Units used in computing earnings per unit		9,488,921		18,386,482		18,392,788

LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

NOTES TO FINANCIAL STATEMENTS (Continued)

(5) Partnership Investments

Accord Partnership

In November 2002, Legacy purchased a combined 34.7% interest in Accord Resources, Ltd, (Accord), a partnership formed specifically to acquire various working interests in oil and natural gas properties located in Wise, Young and Jack County, Texas. Legacy s cash investment in Accord was approximately $467,000 and was accounted for by the equity method. Moriah Resources, Inc. was the general partner of Accord and responsible for daily operation of the properties.

Cash distributions received by Legacy from the partnership for the year ended December 31, 2004 were approximately $103,950. Effective March 31, 2004, Accord was dissolved and the interests in the oil and natural gas properties were distributed to each of the partners, including Legacy. On April 1, 2004, in conjunction with the other Accord partners, Legacy sold all of its interests in the oil and natural gas properties to Aspen Integrated Oil and Gas, L.L.C. for approximately $2.0 million resulting in a gain on sale of assets of approximately $1.3 million. The following table reflects net income information for the Accord Partnership on a gross basis.

	Three Months Ended March 31, 2004
Oil and natural gas revenues	$ 1,129,819
Other operating revenues	174,517
Direct lease operating expenses	(431,595)
Production taxes	(71,105)
Depletion, depreciation and accretion	(129,873)
Other expenses	(7,958)
Operating income	663,805
Other expense	(134,298)
Partnership net income	$ 529,507

MBN Properties LP and MBN Management LLC

MBN Properties LP, a Delaware limited partnership, and its 1% general partner, MBN Management LLC, a Delaware limited liability company, (collectively the MBN Group) were formed in 2005 to acquire and operate oil and natural gas producing properties in partnership with Brothers Production Properties, Ltd., and certain third party investors. On July 22, 2005, MPL advanced $1,649,132 in the form of $462 of paid in capital (46.2% partnership equity interest) and subordinated notes receivable of $1,648,670 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 in Note 4 above. On September 13, 2005, MPL advanced MBN Properties LP an additional $17,598,000 under the subordinated note receivable in conjunction with the closing of the PITCO acquisition described in Note 4 above. The subordinated note receivable from MBN Properties LP was due on July 15, 2012 and bore interest payable quarterly at the rate the Moriah Group paid under its New Facility plus 4%. The other investors in MBN Properties, LP loaned money on similar terms. The notes payable to the other investors (which have not been eliminated in consolidation) are reflected as subordinated notes payable-partners in the accompanying consolidated balance sheet. 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 (46.7% partnership equity interest) and the balance of $653,632 was in a subordinated note receivable from MBN Management LLC due July 15, 2012 and bearing interest at 7%. At December 31, 2005, MBN Properties LP had a payable

LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

NOTES TO FINANCIAL STATEMENTS (Continued)

to MBN Management LLC in the amount of $194,907 related to advances made to MBN Properties LP during the period from inception through December 31, 2005. All amounts owned by MBN Properties LP and MBN Management LLC to Legacy were repaid on March 15, 2006 in connection with the Formation Transactions.

The following tables reflect condensed balance sheet and net loss information for MBN Management LLC on a gross basis:

	December 31, 2005
Current assets	$ 1,233,338
Other assets	31,899
Total assets	$ 1,265,237
Current liabilities	$ 640,727
Notes payable affiliated entities	1,952,753
Members capital	(1,328,243)
Total liabilities and members capital	$ 1,265,237

	From Inception Through December 31, 2005	January 1, 2006 to March 14, 2006
General and administrative expenses	$ (1,278,685)	$ (522,569)
Operating loss	(1,278,685)	(522,569)
Other expense	(50,558)	(21,961)
Net loss	$ (1,329,243)	$ (544,530)

(6) Related Party Transactions

Cary Brown and Dale Brown, as owners of the Moriah Group, and the Brothers Group own a combined non-controlling 18% interest as limited partners in the partnership which owns the building that Legacy occupies. Monthly rent is $6,838, without respect to property taxes and insurance. Prior to the Legacy Formation, the Moriah Group s portion of this rent was reimbursed by the Moriah Group to Petroleum Strategies, Inc., an affiliated entity which is owned by Cary Brown and Dale Brown. 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. Amounts charged were $677,160, $838,899 and $445,267 for the years ended December 31, 2004, 2005 and 2006, respectively. 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 $8,904, $23,472 and $40,392 for the years ended December 31, 2004, 2005 and 2006, respectively.

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LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

NOTES TO FINANCIAL STATEMENTS (Continued)

Legacy has a receivable of $12,332 from three of its employees at December 31, 2006 related to federal income tax withholding on the partnership distributions received by these employees on their unvested restricted units of Legacy Reserves LP. Any distributions on their unvested units are treated as compensation subject to withholding. The employees reimbursed Legacy for this amount prior to January 15, 2007.

Distribution of Oil and Natural Gas Properties to Owners

In December 2003, MPL distributed a property interest equivalent to 10% of its working interest in certain oil and natural gas properties equally to Dale Brown and Cary Brown. Subsequently, in December 2003 and January 2004, Dale and Rita Brown contributed to Charities Support Foundation Inc. (CSFI) and Moriah Foundation Inc. (MFI) and Cary and Jill Brown contributed to Charities Support Foundation Inc. and Cary Brown Family Foundation (CBFF), undivided interests in producing oil and natural gas properties in which Moriah Properties, Ltd. also owned an interest. CSFI owned working interests burdened by net profits interests owned by MFI and CBFF. CSFI had contracted with MRI to provide certain accounting and management services related to the ownership of these oil and gas interests. These properties were reacquired on March 15, 2006 as part of the Legacy Formation.

(7) 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.

(8) 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 Legacy s 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

Legacy s 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 2004, 2005, 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 Legacy s sales is presented in Note 11.

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LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

NOTES TO FINANCIAL STATEMENTS (Continued)

(9) Oil and Natural Gas Swaps

Due to the volatility of oil and natural gas prices, Legacy periodically enters into price-risk management transactions (e.g., swaps) 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 Legacy s ability to benefit from increases in the price of oil and natural gas, it also reduces Legacy s potential exposure to adverse price movements. Legacy s 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 Legacy s 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 hedge Legacy s 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 hedge 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, 2004, 2005, and 2006, Legacy included in revenue realized and unrealized losses related to its oil and natural gas derivatives. The impact on total revenue from hedging activities was as follows:

		December 31,	
	2004	2005	2006
Crude oil derivative contract settlements	$ 46,020	$ (3,530,651)	$ (6,666,755)
Natural gas derivative contract settlements	(119,850)		6,404,533
Unrealized change in fair value oil contracts	(678,803)	(910,738)	4,338,459
Unrealized change in fair value natural gas contracts	119,850	(1,717,476)	5,212,233
	$ (632,783)	$ (6,158,865)	$ 9,288,470

In its statement of cash flows for the year ended December 31, 2005, Legacy classified $3,530,651 paid to settle crude oil derivative contracts as cash used in operating activities. In the accompanying statement of cash flows, the classification of such payments has been revised and they are classified as cash used in investing activities for the year ended December 31, 2005.

In June 2005, Legacy paid its counterparty approximately $3.5 million to cancel and reset 2006 oil swaps from $51.31 to $59.38 per barrel. On July 22, 2005 Legacy paid approximately $0.8 million for an option to enter into a $55.00 per barrel oil swap related to the PITCO acquisition that was not exercised.

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.

LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

NOTES TO FINANCIAL STATEMENTS (Continued)

As of December 31, 2006, 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	Annual Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
2007	671,637	$ 67.62	$ 64.15 - $75.70
2008	618,689	$ 67.11	$ 62.25 - $73.45
2009	571,453	$ 64.46	$ 61.05 - $71.40
2010	426,687	$ 61.51	$ 60.15 - $61.90

As of December 31, 2006, Legacy had the following NYMEX Henry Hub 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	Annual Volumes (Mcf)	Average Price per Mcf	Price Range per Mcf
2007	1,558,504	$ 9.56	$ 9.02 - $11.83
2008	1,422,732	$ 8.61	$ 7.98 - $10.58
2009	1,316,354	$ 8.38	$ 7.77 - $10.18
2010	1,218,899	$ 7.99	$ 7.37 - $ 9.73

As of December 31, 2006, 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 follow Waha more closely than NYMEX:

Calendar Year	Annual Volumes (Mcf)	Basis Range per Mcf
2007	1,560,000	$ (0.88)
2008	1,422,000	$ (0.84)
2009	1,320,000	$ (0.68)
2010	1,200,000	$ (0.57)

(10) Discontinued Operations

During 2004, Legacy disposed of certain producing oil and natural properties which meet the guidelines for treatment as discontinued operations under FAS 144. The following table sets for the operating results for the discontinued operations:

	Year Ended December 31, 2004
Oil sales	$ 24,625
Natural gas sales	51
Oil and natural gas production expenses	(8,553)
Production and other taxes	(1,142)
Depreciation, depletion and amortization	
Income from discontinued operations	14,981
Gain on disposal	7,165
Total income from discontinued operations	$ 22,146

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LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

NOTES TO FINANCIAL STATEMENTS (Continued)

(11) Sales to Major Customers

Legacy operates as one business segment within the Permian Basin region. It sold oil and natural gas production representing 10% or more of total revenues for the years ended December 31, 2004, 2005 and 2006 as shown below:

	2004	**2005**	**2006**
Conoco Phillips	9%	10%	4%
Navajo Crude Oil Marketing	17%	16%	12%
Plains Marketing, LP	20%	18%	14%

In the exploration, development and production business, production is normally sold to relatively few customers. Substantially all of the Legacy s 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.

(12) 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 Legacy s 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 over the useful life of the related asset.

The following table reflects the changes in the ARO during the years ended December 31, 2005 and 2006.

	December 31,	
	2005	**2006**
Asset retirement obligation beginning of period	$ 1,952,866	$ 2,302,147
Liabilities incurred in Legacy formation		1,467,241
Liabilities incurred with properties acquired	446,901	1,888,954
Liabilities incurred with properties drilled		22,882
Liabilities settled during the period	(53,852)	(213,343)
Current period accretion	109,429	242,432
Current period revisions to accretion expense	(163,281)	
Current period revisions to oil and natural gas properties	10,084	782,467
Asset retirement obligation end of period	$ 2,302,147	$ 6,492,780

The discount rate used in calculating the ARO was 6.0% in 2005 and 7.25% at December 31, 2006. These rates approximate Legacy s borrowing rates.

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LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

NOTES TO FINANCIAL STATEMENTS (Continued)

(13) Earnings Per Unit

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

	December 31, 2004	2005	2006
Income available to unitholders	$ 9,194	$ 5,859	$ 4,357
Weighted average units outstanding	9,488,921	9,488,921	16,567,287
Effect of dilutive securities:			
Restricted units			1,592
Weighted average units and potential units outstanding	9,488,921	9,488,921	16,568,879
Basic earnings per unit	$ 0.97	$ 0.62	$ 0.26
Diluted earnings per unit	$ 0.97	$ 0.62	$ 0.26

At December 31, 2006, options to purchase 260,000 units at exercise prices ranging from $17.00 to $17.25 per unit were outstanding, but were not included in the computation of diluted earnings per share due to their antidilutive effect.

(14) 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, 2006 grants of awards covering 333,866 units have been made. The plan is administered by the compensation committee of the board of directors of its general partner. SFAS No. 123(R), Share-Based Payment 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. Since Legacy had no restricted or unit option awards prior to March 15, 2006, there were no adoption or transition consequences as contemplated by SFAS No. 123(R). Pursuant to the provisions of SFAS 123(R), Legacy s issued units, as reflected in the accompanying consolidated balance sheet at

December 31, 2006 does not include 65,116 units related to unvested restricted unit awards.

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 $270,039 for the year ended December 31, 2006. As of December 31, 2006, there was a total of $836,932 of unrecognized compensation costs related to the non-vested portion of these restricted units. At December 31, 2006, this cost was expected to be recognized over a weighted-average period of 2.5 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 Legacy s board. The value of each unit was $17.00 at the time of grant.

LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

NOTES TO FINANCIAL STATEMENTS (Continued)

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. All options granted in 2006 expire five years from the grant date and are exercisable when they vest.

For the year ended December 31, 2006, Legacy recorded $115,316 of compensation expense based on its use of the Black Scholes model to estimate the grant-date fair value of these unit option awards. As of December 31, 2006, there was a total of $533,140 of unrecognized compensation costs related to the non-vested portion of these unit option awards. At December 31, 2006, this cost was expected to be recognized over a weighted-average period of 2.2 years. Compensation expense is based upon straight line amortization of the grant-date fair value over the vesting period of the underlying unit option. Since Legacy is a newly public company and has minimal trading history, it has used an estimated volatility factor of approximately 37% based upon a representative group of publicly-traded companies in the energy industry and employed the fair value method to estimate the grant-date fair value to be amortized over the vesting periods of the unit options awarded. In the absence of historical data, Legacy has assumed an estimated forfeiture rate of 5%. As required by SFAS No. 123(R), the Company will adjust the estimated forfeiture rate based upon actual experience. Legacy has assumed an annual distribution rate of $1.64 per unit.

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

	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term
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 exercisable at December 31, 2006		$	

The following table summarizes the status of the Company s non-vested stock options since January 1, 2006:

	Non-Vested Options	
	Number of Shares	Weighted-Average Fair Value

Non-vested at January 1, 2006		$	
Granted	273,000		2.62
Vested			
Forfeited	(13,000)		2.62
Non-vested at December 31, 2006	260,000	$	2.62

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LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

NOTES TO FINANCIAL STATEMENTS (Continued)

Legacy has used a weighted-average risk free interest rate of 4.9% in its Black Scholes calculation of grant-date fair value, which is based on U.S. Treasury interest rates at the time of the grant whose term is consistent with the expected life of the stock options. Expected life represents the period of time that options are expected to be outstanding and is based on the Company s best estimate. The following table represents the weighted average assumptions used for the Black-Scholes option-pricing model:

	Year Ended December 31, 2006
Expected life (years)	6
Annual Interest rate	4.9%
Annual distribution rate per unit	$ 1.64
Volatility	37%

(15) 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,		
	2004	2005	2006
Development costs	$ 1,636,989	$ 1,958,455	$ 17,325,052
Exploration costs	822		
Acquisition costs:			
Proved properties	1,645,539	65,405,917	187,006,693
Unproved properties		2,928	
Total acquisition, development and exploration costs	$ 3,283,350	$ 67,367,300	$ 204,331,745

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.

LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

NOTES TO FINANCIAL STATEMENTS (Continued)

(16) 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, 2004, 2005 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 PITCO acquisition in September 2005 which is reflected in the December 31, 2005 balances and 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. 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 and Condensate (MBbls)	Natural Gas (MMcf)
Total Proved Reserves:		
Balance, December 31, 2003	3,330	10,274
Purchases of minerals-in-place	228	256
Sales of minerals-in-place	(5)	(2)
Extensions and discoveries	120	467
Revisions of previous estimates due to infill drilling, recompletions and stimulations	86	33
Revisions of previous estimates due to prices and performance	637	225
Production	(287)	(783)
Balance, December 31, 2004	4,109	10,470
Purchases of minerals-in-place	3,541	12,800
Revisions of previous estimates due to infill drilling, recompletions and stimulations	794	1,258
Revisions of previous estimates due to prices and performance	28	956
Production	(354)	(1,027)
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
Proved Developed Reserves:		
December 31, 2003	3,330	10,274
December 31, 2004	4,109	10,470
December 31, 2005	6,380	20,618

December 31, 2006	11,132	28,126

(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.

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LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

NOTES TO FINANCIAL STATEMENTS (Continued)

(17) 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 MBN/PITCO acquisition properties from September 2005, 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 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 Legacy s 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. There are no future income tax expenses because Legacy is a flow-through entity.

		December 31,	
	2004	**2005(a)**	**2006**
		(Thousands)	
Future production revenues	$ 220,989	$ 684,021	$ 947,914
Future costs:			
Production	(95,780)	(242,796)	(387,238)
Development	(178)	(27,609)	(43,419)
Future net cash flows before income taxes	125,031	413,616	517,257
10% annual discount for estimated timing of cash flows	(64,674)	(221,619)	(276,694)
Standardized measure of discounted net cash flows	$ 60,357	$ 191,997	$ 240,563

(a) Includes $93.0 million of standardized measure held by MBN Properties LP of which $50.2 million was owned by the non-controlling interest.

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,	
	2004	**2005**	**2006**
Oil (per Bbl)	$ 40.55	$ 57.64	$ 56.73
Natural Gas (per MMBtu)	$ 5.19	$ 8.82	$ 5.82

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LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

NOTES TO FINANCIAL STATEMENTS (Continued)

The following table summarizes the principal sources of change in the standardized measure of discounted future estimated net cash flows which reflects the PITCO acquisition in 2005 and 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:

	Year Ended December 31,		
	2004	2005	2006
		(Thousands)	
Increase (decrease):			
Sales, net of production costs	$ (9,685)	$ (17,532)	$ (40,113)
Net change in sales prices, net of production costs	10,605	36,574	(60,531)
Changes in estimated future development costs	(86)	(21,401)	4,582
Extensions and discoveries, net of future production and development costs	2,370		2,723
Revisions of previous estimates due to infill drilling, recompletions and stimulations	836	19,319	7,919
Revisions of previous estimates due to prices and performance	6,959	3,156	(12,232)
Previously estimated development costs incurred		(178)	9,517
Purchase of minerals-in place	3,236	102,289	127,009
Sales of minerals in place	(36)		
Other	1,287	4,458	(2,971)
Accretion of discount	3,486	4,955	12,663
Net increase	18,972	131,640	48,566
Standardized measure of discounted future net cash flows:			
Beginning of year	41,385	60,357	191,997
End of year	$ 60,357	$ 191,997	$ 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.

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LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

NOTES TO FINANCIAL STATEMENTS (Continued)

(18) Selected Quarterly Financial Data (Unaudited)

For the three-month periods ended:

	March 31	June 30	September 30	December 31
2006				
Revenues:				
Oil sales	$ 7,440	$ 11,800	$ 13,204	$ 12,907
Natural gas sales	2,995	3,588	4,239	3,624
Realized and unrealized gain (loss) on oil and natural gas swaps	(3,896)	(9,176)	18,606	3,755
Total revenues	6,539	6,212	36,049	20,286
Expenses:				
Oil and natural gas production	2,677	3,186	4,297	5,778
Production and other taxes	738	943	1,030	1,035
General and administrative(a)	956	1,253	1,057	426
Dry hole costs				
Depletion, depreciation, amortization and accretion	2,388	4,967	5,346	5,693
Impairment of long-lived assets			8,573	7,540
Loss on sale of assets				42
Total expenses	6,759	10,349	20,303	20,514
Operating income (loss)	(220)	(4,137)	15,746	(228)
Interest income	33	5	55	36
Interest expense	(1,445)	(1,210)	(1,857)	(2,133)
Other income (expense)	(303)			14
Net income (loss)	$ (1,935)	$ (5,342)	$ 13,944	$ (2,311)
Net income (loss) per share basic and diluted	$ (0.17)	$ (0.29)	$ 0.76	$ (0.13)
Production volumes:				
Oil (MBbl)	129	184	203	233
Natural Gas (MMcf)	434	594	571	601
Total (Mboe)	201	283	298	333

(a) General and administrative expenses for the quarter ended December 31, 2006 reflect an adjustment to reverse certain accruals which had been recorded during the first three quarters and were not deemed necessary.

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LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

NOTES TO FINANCIAL STATEMENTS (Continued)

For the three-month periods ended:

	March 31	June 30	September 30	December 31
2005				
Revenues:				
Oil sales	$ 3,010	$ 3,465	$ 4,944	$ 6,806
Natural gas sales	1,061	1,111	1,700	3,446
Realized and unrealized gain (loss) on oil and natural gas swaps		(1,908)	(5,741)	1,491
Total revenues	4,071	2,668	903	11,743
Expenses:				
Oil and natural gas production	1,012	1,127	1,471	2,765
Production and other taxes	321	353	467	495
General and administrative	101	120	218	915
Dry hole costs				
Depletion, depreciation, amortization and accretion	169	162	404	1,556
Impairment of long-lived assets				
Loss on sale of assets				21
Total expenses	1,603	1,762	2,560	5,752
Operating income (loss)	2,468	906	(1,657)	5,991
Interest income	54	49	51	32
Interest expense	(9)	(5)	(279)	(1,292)
Other income (expense)	14	12	(319)	(157)
Non-controlling interest			1	
Net income (loss)	$ 2,527	$ 962	$ (2,203)	$ 4,574
Net income (loss) per share basic and diluted	$ 0.27	$ 0.10	$ (0.23)	$ 0.48
Production volumes:				
Oil (MBbl)	75	78	79	122
Natural Gas (MMcf)	201	195	235	396
Total (Mboe)	108	111	118	188

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LEGACY RESERVES LP (FORMERLY MORIAH GROUP)

NOTES TO FINANCIAL STATEMENTS (Continued)

(19) Subsequent Events

On January 3, 2007, the board of directors of Legacy s general partner declared a $0.41 per unit cash distribution to all unitholders of record on January 10, 2007. This distribution was paid on February 14, 2007.

On January 18, 2007, Legacy closed its initial public offering of 6,900,000 units representing limited partner interests at an initial public offering price of $19.00 per unit. Net proceeds to the partnership after underwriting discounts and estimated offering expenses were approximately $120 million, all of which will be used to repay all indebtedness outstanding under the partnership s credit facility and for general partnership purposes.

On January 30, 2007, Legacy purchased oil and natural gas properties in West Texas in exchange for 95,000 units at a market price of $23.90 per unit. This acquisition will be accounted for as a purchase of oil and natural gas assets.

On March 20, 2007, Legacy entered into a definitive purchase agreement to acquire certain oil and natural gas producing properties from Nielson & Associates, Inc., for an aggregate purchase price of $45 million, subject to purchase price adjustments, to be paid $30 million in cash with the remainder to be paid with the issuance of 611,247 Legacy units at closing. The properties are located in the East Binger (Marchand) Unit in Caddo County, Oklahoma. The acquisition is subject to customary closing conditions and is expected to close in mid-April, 2007. This acquisition will be accounted for as a purchase of oil and natural gas assets.

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INDEX TO EXHIBITS

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 Reserve LP s Registration Statement on Form S-1 (File No. 33-134056) filed May 12, 2006, included as Appendix A to the Prospectus and including specimen unit certificate for the units)
3.3	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)
3.4	Amended and Restated Limited Liability Company Agreement 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 3.4)
4.1	Registration Rights Agreement dated as of March 15, 2006 by and among Legacy Reserves LP, Legacy Reserves GP, LLC and Friedman, Billings, Ramsey & Co. (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 4.1)
4.2	Registration Rights Agreement dated June 29, 2006 between Henry Holding LP and Legacy Reserves LP and Legacy Reserves GP, LLC (the Henry Registration Rights Agreement) (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006 Exhibit 4.2)
4.3	Registration Rights Agreement dated March 15, 2006 by and among Legacy Reserves LP, Legacy Reserves GP, LLC and the other parties thereto (the Founders Registration Rights Agreement) (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006 Exhibit 4.3)
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 LP s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.1)
10.2	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 LP s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.2)
10.3	Omnibus 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 LP s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.3)
10.4	Purchase/Placement Agreement dated as of March 6, 2006 by and among Legacy Reserves LP, Legacy Reserves GP, LLC and the other parties thereto (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.4)
10.5	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)
10.6	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)

10.7	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)
10.8	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)

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Exhibit Number	Description
10.9	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)
10.10	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)
10.11	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)
10.12	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)
10.13	Employment Agreement dated as of March 15, 2006 between William M. Morris 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 10.13)
10.14	First Amendment to Credit Agreement effective as of July 7, 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 LP s Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006, Exhibit 10.14)
10.15	Purchase and Sale Agreement dated June 29, 2006 between Kinder Morgan Production Company LP and Legacy Reserves Operating LP (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed October 5, 2006, Exhibit 10.15)
10.16	Purchase and Sale Agreement dated June 13, 2006 between Henry Holding LP and Legacy Reserves Operating LP (Incorporated by reference to Legacy Reserves LP s Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006, Exhibit 10.16)
10.17	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)
21.1	List of subsidiaries 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 21.1)
23.1*	Consent of LaRoche Petroleum Consultants, Ltd.
31.1*	Rule 13a-14(a) Certifications (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