Hiland Partners, LP
Form 424B4
November 16, 2005

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Registration No.: 333-129373

PROSPECTUS

1,600,000 Common Units

Representing Limited Partner Interests

We are offering 1,600,000 common units representing limited partner interests. Our common units are traded on the NASDAQ National Market under the symbol "HLND." On November 15, 2005, the last reported sale price of our common units on the NASDAQ National Market was $41.77 per common unit.

Investing in our common units involves risk. Please read "Risk Factors" beginning on page 15.

These risks include the following:

- We may not have sufficient cash after the establishment of cash reserves and payment of our general partner's fees and expenses to enable us to pay distributions at the current level.
- A significant decrease in natural gas production in our areas of operation would reduce our ability to make distributions to our unitholders.
- We depend on certain key producers for a significant portion of our supply of natural gas, and the loss of any of these key producers could reduce our supply of natural gas and adversely affect our financial results.
- Our cash flow is affected by the volatility of natural gas and NGL product prices, which could adversely affect our ability to make distributions to unitholders.
- Due to our lack of asset diversification, adverse developments in our midstream operations would reduce our ability to make distributions to our unitholders.

Harold Hamm controls our general partner, which has sole responsibility for conducting our business and managing our operations. Affiliates of Harold Hamm and our general partner have conflicts of interest and limited fiduciary duties, which may permit them to favor their own interests to your detriment.

Unitholders have limited voting rights and limited ability to influence our operations and activities.

Our general partner determines the cost reimbursement and fees payable to it from us; such payments may be substantial and could reduce our cash available for distribution to you.

Even if unitholders are dissatisfied, they cannot remove our general partner without its consent.

The control of our general partner may be transferred to a third party without unitholder consent.

You may be required to pay taxes on income from us even if you do not receive any cash distributions from us.

PRICE $41.77 PER COMMON UNIT

	Per Common Unit	Total
Public offering price	$ 41.770	$ 66,832,000
Underwriting discount	$ 2.088	$ 3,340,800
Proceeds, before expenses, to Hiland Partners, LP	$ 39.682	$ 63,491,200

The underwriters may also purchase up to an additional 240,000 common units from us at the public offering price, less the underwriters' discount, within 30 days from the date of this prospectus to cover over-allotments. The underwriters expect to deliver the common units on or about November 21, 2005.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

A.G. EDWARDS

RAYMOND JAMES

RBC CAPITAL MARKETS

The date of this prospectus is November 16, 2005.

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You should rely only on the information contained in this prospectus. We have not, and the underwriters have not, authorized any other person to provide you with different information. If anyone provides you with different or inconsistent information, you should not rely on it. We are not, and the underwriters are not, making an offer to sell these securities in any jurisdiction where an offer or sale is not permitted.

PROSPECTUS SUMMARY

This summary provides a brief overview of information contained elsewhere in this prospectus. Because it is abbreviated, this summary may not contain all of the information that you should consider before investing in our common units. You should read the entire prospectus carefully, including the historical and pro forma financial statements and the notes to those financial statements. The information presented in this prospectus assumes that the underwriters' over-allotment option is not exercised. You should read "Risk Factors" beginning on page 15 for more information about important risks that you should consider carefully before buying our common units.

Unless the context otherwise requires, references in this prospectus (1) to "Hiland Partners, LP," "we," "our," "us," or like terms refer to Hiland Partners, LP and its operating subsidiaries, (2) to our historical financial information for periods on or prior to February 14, 2005 refer to the historical financial information of Continental Gas, Inc., our predecessor, and (3) to our pro forma financial information refer to our historical financial information as adjusted to give effect to our formation transactions and initial public offering, which were completed on February 14, 2005, our acquisition of Hiland Partners, LLC effective as of September 1, 2005, which we refer to as the Bakken acquisition, and this offering. Hiland Partners, LP is the issuer of securities in this offering.

Hiland Partners, LP

Overview

We are a growth oriented midstream energy partnership engaged in gathering, compressing, dehydrating, treating, processing and marketing natural gas, and fractionating, or separating, natural gas liquids, or NGLs. We also provide air compression and water injection services to an oil and gas exploration and production company for use in its oil and gas secondary recovery operations. Our operations are primarily located in the Mid-Continent and Rocky Mountain regions of the United States. In our midstream segment, we connect the wells of natural gas producers in our market areas to our gathering systems, treat natural gas to remove impurities, process natural gas for the removal of NGLs, fractionate NGLs into NGL products and provide an aggregate supply of natural gas and NGL products to a variety of natural gas transmission pipelines and markets. In our compression segment, we provide compressed air and water to Continental Resources, Inc., an exploration and production company wholly owned by affiliates of our general partner. Continental Resources uses the compressed air and water in its oil and gas secondary recovery operations in North Dakota by injecting them into its oil and gas reservoirs to increase oil and gas production from those reservoirs. This increased production of natural gas flows through our midstream systems.

Our midstream assets consist of eight natural gas gathering systems with approximately 1,124 miles of gas gathering pipelines, five natural gas processing plants, three natural gas treating facilities and three NGL fractionation facilities. Our compression assets consist of two air compression facilities and a water injection plant.

We commenced our midstream operations in 1990 when Continental Gas, Inc., then a subsidiary of Continental Resources, constructed the Eagle Chief gathering system in northwest Oklahoma. Since 1990, we have grown through a combination of building gas gathering and processing assets in areas where Continental Resources has active exploration and production assets and through acquisitions of existing systems which we have then expanded. Since inception, we have constructed 322 miles of natural gas gathering pipelines, three natural gas processing plants, two treating facilities and one fractionation facility. In addition, our management team designed and constructed the Bakken gathering system that we recently acquired from an affiliate of our general partner, which consists of 256 miles of gas gathering pipeline, a natural gas processing plant, two compressor stations and one fractionation facility. We have also acquired 546 miles of natural gas gathering pipelines, one natural gas processing plant, one treating facility and one fractionation facility. Our pro forma total segment margin for the year ended December 31, 2004 and for the nine months ended September 30, 2005 was $25.5 million and $26.4 million, respectively. Please read " Non-GAAP Financial Measures" for an explanation of total segment margin and a reconciliation of total segment margin to its most directly comparable financial measure calculated and presented in accordance with generally accepted accounting principles, or GAAP.

Recent Developments

Bakken Acquisition. Effective September 1, 2005, we consummated the Bakken acquisition pursuant to which we acquired the outstanding membership interests in Hiland Partners, LLC, an Oklahoma limited liability company, for approximately $92.7 million in cash, $35.0 million of which was used to retire outstanding Hiland Partners, LLC indebtedness. Hiland Partners, LLC's principal asset is the Bakken gathering system located in eastern Montana. Pursuant to an option contained in the omnibus agreement we entered into with Hiland Partners, LLC and Harold Hamm and his affiliates in connection with our initial public offering, Hiland Partners, LLC granted us an exclusive two-year option to purchase the Bakken gathering system at fair market value at the time of purchase. A mutually-agreed-upon investment banking firm determined the fair market value of the Bakken gathering system, and the conflicts committee of the board of directors of our general partner, consisting of its independent directors, approved the transaction.

The Bakken gathering system is located in an area where a number of exploration and production companies are actively developing crude oil and associated natural gas reserves from the Bakken shale formation. As of September 30, 2005, the Bakken gathering system consisted of approximately 256 miles of gas gathering pipeline, a natural gas processing plant, two compressor stations, which are comprised of three units with an aggregate of approximately 4,434 horsepower, and one fractionation facility. The Bakken processing plant and a portion of the gathering system became operational on November 8, 2004 and the system's peak and average throughput rates during the month of September 2005 were approximately 14,475 Mcf/d and 13,100 Mcf/d, respectively. The gathering system has an initial capacity of approximately 25,000 Mcf/d.

Bank Credit Facility. To facilitate the closing of the Bakken acquisition, we amended our senior secured revolving credit facility to increase our borrowing capacity under the facility from $55.0 million to $125.0 million, consisting of a $117.5 million acquisition facility and a $7.5 million working capital facility. We used a portion of this increased capacity to fund the Bakken acquisition. Upon completion of this offering, we expect to have available capacity of approximately $88.0 million under our acquisition facility for future borrowings. For a more complete description of our credit facility, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Credit Facility."

Distribution Increase. On November 14, 2005, we paid a cash distribution of $0.5125 per unit, or $2.05 per unit on an annualized basis, on our common and subordinated units for the quarter ended September 30, 2005. This distribution represented an increase of 11% from our distribution of $0.4625 per unit for the second quarter of 2005.

As a result of the Bakken acquisition, our management intends to recommend to the board of directors of our general partner an additional quarterly distribution increase of $0.075 per quarter, or $0.30 per unit on an annualized basis, for the first full quarter following the closing of the acquisition. Such an increase would result in a quarterly distribution of $0.5875 per unit, which equals an annualized distribution rate of $2.35 per unit. Subject to the approval of the board of directors of our general partner and the absence of any material adverse developments or potentially attractive opportunities that would make such an increase inadvisable, we expect this increase to be reflected in our distribution declared for the fourth quarter of 2005.

Under our partnership agreement, generally our general partner is entitled to 15% of the amount we distribute to each unitholder in excess of $0.495 per unit per quarter up to $0.5625 per unit per quarter, and 25% of the amount we distribute to each unitholder in excess of $0.5625 per unit per quarter up to $0.675 per unit per quarter.

Badlands Expansion Project. On November 8, 2005, we entered into a new 15-year definitive gas purchase agreement with Continental Resources, Inc. under which we will gather, treat and process additional natural gas, which is produced as a by-product of Continental Resources' secondary oil recovery operations, in the areas specified by the contract. In return, we will receive 50% of the proceeds attributable to residue gas and natural gas liquids sales as well as certain fixed fees associated with gathering and treating the natural gas, including a $0.60 per Mcf fee for the first 36 Bcf of natural gas gathered. The board of directors, as well as the conflicts committee of the board of directors, of our general partner have approved the agreement.

In order to fulfill our obligations under the agreement, we intend to expand our Badlands gas gathering system and processing plant located in Bowman County, North Dakota. This expansion project will include the construction of a 40,000 Mcf/d nitrogen rejection plant and the expansion of our existing Badlands field gathering infrastructure. The expansion project, which is targeted for completion in the 4th quarter of 2006, is expected to cost approximately $40 million, which we intend to fund using our existing bank credit facility. Moreover, we expect to spend an additional $9.5 million in 2007 to expand the system.

Board Member Selections. On May 11, 2005, we announced that the board of directors of our general partner had appointed Rayford T. Reid as a director. Mr. Reid was also named to the compensation committee of the board of directors. On October 3, 2004, we announced that the board of directors of our general partner had appointed Shelby E. Odell as a director. For a more complete description of the board of directors of our general partner, please read "Management Directors and Executive Officers of Hiland Partners GP, LLC."

Midstream Segment

Our midstream assets include the following:

Eagle Chief Gathering System. The Eagle Chief gathering system is a 554-mile gas gathering system located in northwest Oklahoma that gathers, compresses, dehydrates and processes natural gas. Our Eagle Chief gathering system has a capacity of 30,000 Mcf/d and the average volume of natural gas flowing through the system, or throughput, was approximately 20,370 Mcf/d for the nine months ended September 30, 2005. The system represented approximately 27.6% of our pro forma total segment margin for the nine months ended September 30, 2005.

Bakken Gathering System. The Bakken gathering system is a 256-mile gas gathering system located in Richland County, Montana that gathers, compresses, dehydrates and processes natural gas. Our Bakken gathering system has capacity of 25,000 Mcf/d and average throughput was approximately 8,260 Mcf/d for the nine months ended September 30, 2005. The system represented approximately 22.8% of our pro forma total segment margin for the nine months ended September 30, 2005.

Worland Gathering System. The Worland gathering system is a 151-mile gas gathering system located in central Wyoming that gathers, compresses, dehydrates, treats and processes natural gas, and fractionates NGLs. Our Worland gathering system has a capacity of 8,000 Mcf/d and average throughput was approximately 3,110 Mcf/d for the nine months ended September 30, 2005. The system represented approximately 14.9% of our pro forma total segment margin for the nine months ended September 30, 2005.

Badlands Gathering System. The Badlands gathering system is a 108-mile gas gathering system located in southwest North Dakota that gathers, compresses, dehydrates, treats and processes natural gas, and fractionates NGLs. Our Badlands gathering system has a capacity of 5,000 Mcf/d and average throughput was approximately 3,080 Mcf/d for the nine months ended September 30, 2005. The system represented approximately 14.8% of our pro forma total segment margin for the nine months ended September 30, 2005.

Matli Gathering System. The Matli gathering system is a 37-mile gas gathering system located in central Oklahoma that gathers, compresses, dehydrates, treats and processes natural gas. Our Matli gathering system has a capacity of 20,000 Mcf/d and average throughput was approximately 14,640 Mcf/d for the nine months ended September 30, 2005. The system represented approximately 5.2% of our pro forma total segment margin for the nine months ended September 30, 2005.

Other Systems. We also own three natural gas gathering systems located in Texas, Mississippi and Oklahoma. These systems represented approximately 2.0% of our pro forma total segment margin for the nine months ended September 30, 2005.

Compression Segment

We provide air and water compression services to Continental Resources for use in its oil and gas secondary recovery operations under a four-year, fixed-fee contract (which we entered into in connection with our initial public offering) at our Cedar Hills compression facility, our Horse Creek compression facility and our water injection plant located next to our Cedar Hills compression facility. These assets are located in North Dakota in close proximity to our Badlands gathering system. The natural gas produced by Continental Resources flows through our Badlands gathering system. Our compression segment represented approximately 12.7% of our pro forma total segment margin for the nine months ended September 30, 2005.

Summary of Risk Factors

An investment in our common units involves risks associated with our business, regulatory and legal matters, our limited partnership structure and the tax characteristics of our common units. The following list of risk factors is not exhaustive. Please read carefully these and other risks under "Risk Factors."

Risks Related to Our Business

We may not have sufficient cash after the establishment of cash reserves and payment of our general partner's fees and expenses to enable us to pay distributions at the current level.

A significant decrease in natural gas production in our areas of operation would reduce our ability to make distributions to our unitholders.

Our construction of new assets or the expansion of existing assets may not result in revenue increases and is subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our results of operations and financial condition.

We depend on certain key producers for a significant portion of our supply of natural gas, and the loss of any of these key producers could reduce our supply of natural gas and adversely affect our financial results.

Our cash flow is affected by the volatility of natural gas and NGL product prices, which could adversely affect our ability to make distributions to unitholders.

We may incur significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental regulations or an accidental release of hazardous substances into the environment.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. If a significant accident or event occurs that is not fully insured, our operations and financial results could be adversely affected.

Due to our lack of asset diversification, adverse developments in our midstream operations would reduce our ability to make distributions to our unitholders.

Risks Inherent in an Investment in Us

Harold Hamm controls our general partner, which has sole responsibility for conducting our business and managing our operations. Affiliates of Harold Hamm and our general partner have conflicts of interest and limited fiduciary duties, which may permit them to favor their own interests to your detriment.

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.

Even if unitholders are dissatisfied, they cannot remove our general partner without its consent.

The control of our general partner may be transferred to a third party without unitholder consent.

We may issue additional common units without your approval, which would dilute your ownership interests.

Our general partner's discretion in determining the level of cash reserves may reduce the amount of cash available for distribution to you.

Tax Risks to Common 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 treats us as a corporation or we become subject to entity level taxation for state tax purposes, it would substantially reduce the amount of cash available for distribution to you.

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

You may be required to pay taxes on income from us even if you do not receive any cash distributions from us.

Tax gain or loss on disposition of our common units could be more or less than expected.

The sale or exchange of 50% or more of our capital and profits interests will result in the termination of our partnership for federal income tax purposes.

Unitholders may be subject to state and local taxes and return filing requirements.

Competitive Strengths

Based on the following competitive strengths, we believe that we are well positioned to compete in our operating regions:

- We have expertise in developing midstream systems.

- Substantially all of our facilities are modern.

- Our assets are strategically located in major natural gas supply areas and have available capacity.

- We provide an integrated and comprehensive package of midstream services.

- We have the financial flexibility to pursue growth projects.

- We have significant experience operating our assets and a knowledgeable senior management team.

Business Strategies

Our management team is committed to increasing the amount of cash available for distribution per unit by executing the following strategies:

- Engaging in construction and expansion opportunities.

- Pursuing complementary acquisitions.

- Increasing volumes on our existing assets.

- Taking measures that reduce our exposure to commodity price risk.

Summary of Conflicts of Interest and Fiduciary Duties

Hiland Partners GP, LLC, our general partner, has a legal duty to manage our partnership in a manner beneficial to us and our unitholders. This legal duty originates in statutes and judicial decisions and is commonly referred to as a "fiduciary duty." The officers and directors of our general partner have fiduciary duties to manage our general partner in a manner beneficial to its owners. As a result of this relationship, conflicts of interest may arise in the future between us and our unitholders, on the one hand, and our general partner and its affiliates on the other hand.

Our partnership agreement contains provisions that modify and limit the fiduciary duties of our general partner to our unitholders. Our partnership agreement also restricts the remedies available to unitholders for actions that might otherwise constitute breaches of our general partner's fiduciary duty. By purchasing a common unit, you are automatically consenting to various actions contemplated by the partnership agreement and conflicts of interest that might otherwise be considered a breach of fiduciary or other duties under applicable state law.

Partnership Structure

Our operations are conducted through, and our operating assets are owned by, our subsidiaries. We own our interests in our subsidiaries through our operating company, Hiland Operating, LLC. Upon completion of this offering:

- The public unitholders will own 3,860,577 common units, representing a 45.0% limited partner interest in us;

- Harold Hamm, the chairman of the board of directors of our general partner, and members of our management will continue to own, directly or indirectly, a 100% managing member interest in Hiland Partners GP, LLC, our general partner;

- Harold Hamm, the Harold Hamm DST Trust and the Harold Hamm HJ Trust, which we collectively refer to as the Hamm Parties, and members of our management will continue to collectively own, directly or indirectly, a 100% economic interest in Hiland Partners GP, LLC, as well as 467,423 common units and 4,080,000 subordinated units, totaling an aggregate 53.0% limited partner interest in us;

Hiland Partners GP, LLC will continue to own the 2% general partner interest in us as well as the incentive distribution rights; and

We will, directly or indirectly, own all of the membership interests in the operating company and the operating subsidiaries, which own and operate our assets.

Our principal executive offices are located at 205 West Maple, Suite 1100, Enid, Oklahoma 73701 and our phone number is (580) 242-6040.

The diagram on the following page depicts our organization and ownership after giving effect to this offering.

Ownership of Hiland Partners, LP	
Common Units:	
Public Unitholders	45.0%
The Hamm Parties and Management	5.4%
	50.4%
Subordinated Units:	
The Hamm Parties and Management	47.6%
General Partner Interest	2.0%
	100.0%

* Includes 29,109 common units owned by directors of our general partner, excluding management directors and Harold Hamm.

THE OFFERING

Common units offered to the public	1,600,000 common units.
	1,840,000 common units if the underwriters exercise their over-allotment option in full.
Units outstanding after this offering	4,328,000 common units, representing an approximate 50.4% limited partner interest in us, and
	4,080,000 subordinated units, representing an approximate 47.6% limited partner interest in us.
Use of proceeds	We anticipate using the aggregate net proceeds of approximately $64.2 million from this offering, after deducting underwriting discounts and commissions and other offering expenses, and our general partner's proportionate capital contribution to repay a portion of indebtedness outstanding under our senior secured revolving credit facility, which was incurred to fund the Bakken acquisition. Please read "Use of Proceeds."
Cash distributions	Common unitholders are entitled to receive quarterly distributions of $0.45 per unit prior to any distribution on the subordinated units to the extent we have sufficient cash from our operations after we have paid our expenses, including the expenses of our general partner. In general, we will pay any cash distribution we make each quarter in the following manner:
	first, 98% to the common units and 2% to our general partner, until each common unit has received a minimum quarterly distribution of $0.45 plus any arrearages from prior quarters;
	second, 98% to the subordinated units and 2% to our general partner, until each subordinated unit has received a minimum quarterly distribution of $0.45; and
	third, 98% to all units, pro rata, and 2% to our general partner, until each unit has received a distribution of $0.495.
	If cash distributions per unit exceed $0.495 in any quarter, our general partner will receive increasing percentages, up to a maximum of 50% of the cash we distribute in excess of that amount. We refer to these distributions as "incentive distributions."
	We must distribute all of our cash on hand at the end of each quarter, less reserves established by our general partner in its discretion. We refer to this cash as "available cash," and we define its meaning in our partnership agreement and in the glossary of terms attached as Appendix A. The amount of available cash may be greater than or less than the minimum quarterly distribution.

Subordinated units	The principal difference between our common units and subordinated units is that in any quarter during the subordination period, holders of the subordinated units are entitled to receive the minimum quarterly distribution of $0.45 per unit only after the common units have received the minimum quarterly distribution plus arrearages in the payment of the minimum quarterly distribution from prior quarters.
	Accordingly, the distribution on the subordinated units may be reduced or eliminated if necessary to ensure the common units receive their minimum quarterly distribution. Subordinated units will not accrue arrearages. The subordination period will end once we meet certain financial tests, but not before March 31, 2010. These financial tests require us to have earned and paid the minimum quarterly distribution on all of our outstanding units for three consecutive four-quarter periods.
	When the subordination period ends, all remaining subordinated units will convert into common units on a one-for-one basis, and the common units will no longer be entitled to arrearages.
Early conversion of subordinated units	If we meet the applicable financial tests for any three consecutive four-quarter periods ending on or after March 31, 2008, 25% of the subordinated units will convert into common units. If we meet these tests for any three consecutive four-quarter periods ending on or after March 31, 2009, an additional 25% of the subordinated units will convert into common units. The early conversion of the second 25% of the subordinated units may not occur until at least one year after the early conversion of the first 25% of the subordinated units.
Issuance of additional units	In general, during the subordination period, we may issue up to 1,360,000 additional common units without obtaining unitholder approval. We can also issue an unlimited number of common units in connection with acquisitions and capital improvements that increase cash flow from operations per unit on an estimated pro forma basis. We can also issue additional common units if the proceeds are used to repay certain of our indebtedness.

Limited voting rights	Our general partner manages and operates us. Unlike the holders of common stock in a corporation, you will have only limited voting rights on matters affecting our business. You will have no right to elect our general partner or its directors on an annual or other continuing basis. Our general partner may not be removed except by a vote of the holders of at least $66^2/_3$% of the outstanding units, including any units owned by our general partner and its affiliates, voting together as a single class. Following the closing of this offering, our general partner and its affiliates will own an aggregate of 54.1% of our common and subordinated units. This will give our general partner the practical ability to prevent its involuntary removal.
Limited call right	If at any time our general partner and its affiliates own more than 80% of the outstanding common units, our general partner has the right, but not the obligation, to purchase all of the remaining common units at a price not less than the then-current market price of the common units.
Estimated ratio of taxable income to distributions	We estimate that if you own the common units you purchase in this offering through the record date for distributions for the period ending December 31, 2008, you will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be 20% or less of the cash distributed to you with respect to that period. For the basis of this estimate, please read "Material Tax Consequences Tax Consequences of Unit Ownership Ratio of Taxable Income to Distributions."
Exchange listing	Our common units are traded on the NASDAQ National Market under the symbol "HLND."

SUMMARY HISTORICAL AND PRO FORMA FINANCIAL AND OPERATING DATA

The following table shows summary historical financial and operating data and pro forma financial data for the periods and as of the dates indicated. The summary historical financial data for the years ended December 31, 2002, 2003 and 2004 are derived from our audited financial statements. The summary historical financial data as of and for the nine months ended September 30, 2004 and 2005 are derived from our unaudited financial statements. Our historical financial data for the periods prior to February 15, 2005 reflect the historical financial data for Continental Gas, Inc., our predecessor. The summary pro forma financial data as of September 30, 2005 and for the year ended December 31, 2004 and nine months ended September 30, 2005 are derived from our unaudited pro forma financial statements.

The unaudited pro forma balance sheet data give pro forma effect to this offering of common units and our general partner's proportionate capital contribution as if they had occurred on September 30, 2005. The unaudited pro forma summary of operations data give pro forma effect to the following transactions as if they had occurred on January 1, 2004:

- the Bakken acquisition;
- borrowings under our amended credit facility to fund the Bakken acquisition;
- this offering of common units and our general partner's proportionate capital contribution; and
- our initial public offering of common units and the formation transactions related to our partnership.

The following table includes the non-GAAP financial measures of (1) EBITDA and (2) total segment margin, which consists of midstream segment margin and compression segment margin. We define EBITDA as net income (loss) plus interest expense, provision for income taxes and depreciation, amortization and accretion expense. We define midstream segment margin as midstream revenue less midstream purchases. Midstream purchases include the following costs and expenses: cost of natural gas and NGLs purchased by us from third parties, cost of natural gas and NGLs purchased by us from affiliates, and cost of crude oil purchased by us from third parties. We define compression segment margin as the revenues derived from our compression segment. For a reconciliation of these non-GAAP financial measures to their most directly comparable financial measures calculated and presented in accordance with GAAP, please read "Non-GAAP Financial Measures."

Maintenance capital expenditures represent capital expenditures made to replace partially or fully depreciated assets to maintain the existing operating capacity of our assets and to extend their useful lives, or other capital expenditures that are incurred in maintaining existing system volumes and related cash flows. Expansion capital expenditures represent capital expenditures made to expand or increase the efficiency of the existing operating capacity of our assets. Expansion capital expenditures include expenditures that facilitate an increase in volumes within our operations, whether through construction or acquisition. Expenditures that reduce our operating costs will be considered expansion capital expenditures only if the reduction in operating expenses exceeds cost reductions typically resulting from routine maintenance. We treat costs for repairs and minor renewals to maintain facilities in operating condition and that do not extend the useful life of existing assets as operations and maintenance expenses as we incur them.

	Predecessor				Hiland Partners, LP (1)	Hiland Partners, LP Pro Forma	
	Year Ended December 31,			Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Year Ended December 31, 2004	Nine Months Ended September 30, 2005
	2002	2003	2004				
				(unaudited)			
	(in thousands, except per unit and operating data)						
Summary of Operations Data:							
Total revenues	$ 35,228	$ 76,018	$ 98,296	$ 70,286	$ 98,306	$ 112,631	$ 116,955
Operating costs and expenses:							
Midstream purchases (exclusive of items shown separately below)	27,935	67,002	82,532	59,846	77,548	87,132	90,573
Operations and maintenance	3,509	3,714	4,933	3,624	5,083	7,013	6,762
Depreciation, amortization and accretion	2,370	3,304	4,127	3,003	6,924	9,866	10,902
Property impairment		1,535					
(Gain) loss on asset sales	(12)	34	(19)	(15)		(19)	
Bad debt	295						
General and administrative	730	770	1,082	680	1,539	1,179	1,793
Total operating costs and expenses	34,827	76,359	92,655	67,138	91,094	105,171	110,030
Operating income (loss)	401	(341)	5,641	3,148	7,212	7,460	6,925
Other income (expense):							
Interest expense	(185)	(473)	(702)	(508)	(766)	(1,329)	(1,609)
Amortization of deferred loan costs		(24)	(102)	(76)	(360)	(818)	(649)
Interest income and other	72	10	40	23	112	41	115
Total other income (expense)	(113)	(487)	(764)	(561)	(1,014)	(2,106)	(2,143)
Income (loss) from continuing operations	288	(828)	4,877	2,587	6,198	5,354	4,782
Discontinued operations, net	199	246	35	34			
Income (loss) before change in accounting principle	487	(582)	4,912	2,621	6,198	5,354	4,782
Cumulative effect of change in accounting principle		1,554					
Net income	$ 487	$ 972	$ 4,912	$ 2,621	$ 6,198	$ 5,354	$ 4,782
Net income per limited partner unit basic					$ 0.82	$ 0.62	$ 0.56
Net income per limited partner unit diluted					$ 0.82	$ 0.62	$ 0.55
Balance Sheet Data (at period end):							
Property and equipment, at cost, net	$ 23,722	$ 38,425	$ 37,075	$ 37,766	$ 116,239		$ 116,239

Total assets	28,058	47,840	49,175	46,774	186,551		186,551
Accounts payable affiliates	2,150	2,814	2,998	2,431	7,660		7,660
Long-term debt	3,491	14,571	12,643	12,750	93,700		29,520
Net equity/Partners' capital	20,767	21,739	24,510	22,219	71,487		135,667
Cash Flow Data:							
Net cash flow provided by (used in):							
Operating activities	$ 4,809	$ 4,464	$ 7,957	$ 6,911	$ 900		
Investing activities	(5,645)	(17,286)	(5,290)	(4,867)	(65,210)		
Financing activities	516	13,212	(2,946)	(2,257)	70,909		
Other Financial Data:							
Midstream segment margin	$ 7,293	$ 9,016	$ 15,764	$ 10,440	$ 17,746	$ 21,645	$ 23,034
Compression segment margin					3,012	3,854	3,348
Total segment margin	$ 7,293	$ 9,016	$ 15,764	$ 10,440	$ 20,758	$ 25,499	$ 26,382
EBITDA	$ 3,042	$ 4,773	$ 9,843	$ 6,208	$ 14,248	$ 17,367	$ 17,942
Maintenance capital expenditures	$ 1,826	$ 1,769	$ 1,693	$ 1,243	$ 1,462		
Expansion capital expenditures	3,244	14,900	3,474	3,474	1,308		
Discontinued operations	690	745	159	159			
Total capital expenditures	$ 5,760	$ 17,414	$ 5,326	$ 4,876	$ 2,770		
Operating Data:							
Natural gas sales (MMBtu/d)	26,599	37,701	40,560	40,730	43,044	44,080	49,523
NGL sales (Bbls/d)	950	895	1,133	1,095	1,561	1,436	2,419

(1) For the period ended February 14, 2005, these results reflect the historical results of Continental Gas, Inc., our predecessor.

NON-GAAP FINANCIAL MEASURES

We include in this prospectus the non-GAAP financial measures of EBITDA and total segment margin, which consists of midstream segment margin and compression segment margin, and provide reconciliations of these non-GAAP financial measures to their most directly comparable financial measures calculated and presented in accordance with GAAP.

We define EBITDA as net income plus interest expense, provision for income taxes and depreciation, amortization and accretion expense.

EBITDA is used as a supplemental financial measure by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness;
- our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

EBITDA is also a financial measurement that, with certain negotiated adjustments, is reported to our banks and is used as a gauge for compliance with our financial covenants under our credit facility. EBITDA should not be considered an alternative to net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP. Our EBITDA may not be comparable to EBITDA or similarly titled measures of other entities, as other entities may not calculate EBITDA in the same manner as we do.

We define midstream segment margin as midstream revenue less midstream purchases. Midstream purchases include the following costs and expenses: cost of natural gas and NGLs purchased by us from third parties, cost of natural gas and NGLs purchased by us from affiliates, and cost of crude oil purchased by us from third parties. We define compression segment margin as the revenues derived from our compression segment. We view total segment margin as an important performance measure of the core profitability of our operations. The GAAP measure most directly comparable to total segment margin is operating income.

The following table presents a reconciliation of the non-GAAP financial measures of (1) EBITDA to the GAAP financial measure of net income and (2) total segment margin (which consists of the sum of midstream segment margin and compression segment margin) to operating income, in each case, on a historical basis and pro forma for this offering and the application of the net proceeds for each of the periods indicated.

	Predecessor				Hiland Partners, LP	Hiland Partners, LP Pro Forma	
	Year Ended December 31,			Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Year Ended December 31, 2004	Nine Months Ended September 30, 2005
	2002	2003	2004				
				(unaudited)			
	(in thousands)						
Reconciliation of EBITDA to Net Income:							
Net income	$ 487	$ 972	$ 4,912	$ 2,621	$ 6,198	$ 5,354	$ 4,782
Add:							
Depreciation, amortization and accretion	2,370	3,304	4,127	3,003	6,924	9,866	10,902
Amortization of deferred loan costs		24	102	76	360	818	649
Interest expense	185	473	702	508	766	1,329	1,609
EBITDA	$ 3,042	$ 4,773	$ 9,843	$ 6,208	$ 14,248	$ 17,367	$ 17,942
Reconciliation of Total Segment Margin to Operating Income (Loss):							
Operating income (loss)	$ 401	$ (341)	$ 5,641	$ 3,148	$ 7,212	$ 7,460	$ 6,925
Add:							
Operations and maintenance	3,509	3,714	4,933	3,624	5,083	7,013	6,762
Depreciation, amortization and accretion	2,370	3,304	4,127	3,003	6,924	9,866	10,902
Property impairment		1,535					
(Gain) loss on asset sales	(12)	34	(19)	(15)		(19)	
Bad debt	295						
General and administrative	730	770	1,082	680	1,539	1,179	1,793
Total segment margin	$ 7,293	$ 9,016	$ 15,764	$ 10,440	$ 20,758	$ 25,499	$ 26,382

RISK FACTORS

Limited partner interests are inherently different from capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. You should consider carefully the following risk factors together with all of the other information included in this prospectus in evaluating an investment in our common units.

The following risks could materially and adversely affect our business, financial condition or results of operations. In that case, the amount of the distributions on our common units could be materially and adversely affected, the trading price of our common units could decline and you could lose all or part of your investment.

Risks Related to Our Business

We may not have sufficient cash after the establishment of cash reserves and payment of our general partner's fees and expenses to enable us to pay distributions at the current level.

We may not have sufficient available cash each quarter to pay distributions at the current level. Under the terms of our partnership agreement, we must pay our general partner's fees and expenses and set aside any cash reserve amounts before making a distribution to our unitholders. 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 natural gas gathered on our pipelines;
- the throughput volumes at our processing, treating and fractionation plants;
- the price of natural gas;
- the relationship between natural gas and NGL prices;
- the level of our operating costs;
- the weather in our operating areas;
- the level of competition from other midstream energy companies; and
- the fees we charge and the margins we realize for our services.

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

- the level of capital expenditures we make;
- the cost of acquisitions, if any;
- our debt service requirements;
- fluctuations in our working capital needs;

restrictions on distributions contained in our credit facility;

restrictions on our ability to make working capital borrowings under our credit facility to pay distributions;

prevailing economic conditions; and

the amount of cash reserves established by our general partner's board of directors in its sole discretion for the proper conduct of our business.

A decrease in our cash flow will reduce the amount of cash we have available for distribution to our unitholders.

You should be aware that the amount of cash we have available for distribution depends primarily upon our cash flow, including cash flow from financial reserves and working capital borrowings, and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses and may not make cash distributions during periods when we record net income.

A significant decrease in natural gas production in our areas of operation would reduce our ability to make distributions to our unitholders.

Our gathering systems are connected to natural gas reserves and wells, from which the production will naturally decline over time, which means that our cash flows associated with these wells will also decline over time. To maintain or increase throughput levels on our gathering systems and the utilization rate at our processing plants and our treating and fractionation facilities, we must continually obtain new natural gas supplies. Our ability to obtain additional sources of natural gas depends in part on the level of successful drilling activity near our gathering systems.

Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. Drilling activity generally decreases as oil and natural gas prices decrease. We have no control over the level of drilling activity in the areas of our operations, the amount of reserves associated with the wells or the rate at which production from a well will decline. In addition, we have no control over producers or their production decisions, which are affected by, among other things, prevailing and projected energy prices, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulations and the availability and cost of capital. Because we often obtain as new sources of supply associated gas that is produced in connection with oil drilling operations, declines in oil prices, even without a commensurate decline in prices for natural gas, can adversely affect our ability to obtain new gas supplies.

If we fail to obtain new sources of natural gas supply, our revenues and cash flow may be adversely affected and our ability to make distributions to our unitholders reduced.

We may not be able to obtain additional contracts for natural gas supplies. We face competition in acquiring new natural gas supplies. Competition for natural gas supplies is primarily based on the location of pipeline facilities, pricing arrangements, reputation, efficiency, flexibility and reliability. Our major competitors for natural gas supplies and markets include (1) Western Gas Resources, Inc., Ringwood Gathering and Duke Energy Field Services LLC at our Eagle Chief gathering system, (2) Enogex, Inc. at our Matli gathering system and (3) Bear Paw Energy, a subsidiary of Northern Borders Partners, L.P., at our Badlands and Bakken gathering systems. Many of our competitors have greater financial resources than we do which may better enable them to pursue additional gathering and processing opportunities than us.

We depend on certain key producers for a significant portion of our supply of natural gas, and the loss of any of these key producers could reduce our supply of natural gas and adversely affect our financial results.

For the nine months ended September 30, 2005, Continental Resources, Chesapeake Energy and Range Resources supplied us with approximately 40.4%, 28.0% and 12.5%, respectively, of our total natural gas volumes, on a pro forma basis. Each of our natural gas gathering systems is dependent on one or more of these producers. To the extent that these producers reduce the volumes of natural gas that they supply us as a result of competition or otherwise, we would be adversely affected unless we were able to acquire comparable supplies of natural gas on comparable terms from other producers, which may not be possible in areas where the producer that reduces its volumes is the primary producer in the area.

We generally do not obtain independent evaluations of natural gas reserves dedicated to our gathering systems; therefore, volumes of natural gas gathered on our gathering systems in the future could be less than we anticipate.

We generally do not obtain independent evaluations of natural gas reserves connected to our gathering systems due to the unwillingness of producers to provide reserve information as well as the cost of such evaluations. Accordingly, we do not have estimates of total reserves dedicated to our systems or the anticipated life of such reserves. If the total reserves or estimated life of the reserves connected to our gathering systems is less than we anticipate and we are unable to secure additional sources of natural gas, then the volumes of natural gas gathered on our gathering systems in the future could be less than we anticipate. A decline in the volumes of natural gas gathered on our gathering systems would have an adverse effect on our results of operations and financial condition.

We are exposed to the credit risks of our key customers, and any material nonpayment or nonperformance by our key customers could reduce our ability to make distributions to our unitholders.

We are subject to risks of loss resulting from nonpayment or nonperformance by our customers. Any material nonpayment or nonperformance by our key customers could reduce our ability to make distributions to our unitholders. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us.

Our cash flow is affected by the volatility of natural gas and NGL product prices, which could adversely affect our ability to make distributions to unitholders.

We are subject to significant risks due to frequent and often substantial fluctuations in commodity prices. In the past, the prices of natural gas and NGLs have been extremely volatile, and we expect this volatility to continue. The NYMEX daily settlement price for the prompt month contract in 2004 ranged from a high of $8.14 per MMBtu to a low of $4.40 per MMBtu. In the first nine months of 2005, the same index ranged from a high of $14.50 per MMBtu to a low of $5.50 per MMBtu. A composite of the weighted monthly average NGLs price based on our average NGLs composition in 2004 ranged from a high of approximately $0.96 per gallon to a low of $0.61 per gallon. In the first nine months of 2005, the same composite ranged from approximately $1.15 per gallon to approximately $0.71 per gallon. The markets and prices for natural gas and NGLs depend upon factors beyond our control. These factors include demand for oil, natural gas and NGLs, which fluctuate with changes in market and economic conditions and other factors, including:

- the impact of weather on the demand for oil and natural gas;
- the level of domestic oil and natural gas production;
- the availability of imported oil and natural gas;
- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems;
- the availability and marketing of competitive fuels;
- the impact of energy conservation efforts; and

the extent of governmental regulation and taxation.

We operate under two types of contractual arrangements under which our total segment margin is exposed to increases and decreases in the price of natural gas and NGLs: percentage-of-proceeds and percentage-of-index arrangements. Under percentage-of-proceeds arrangements, we generally purchase natural gas from producers for an agreed percentage of proceeds or upon an index related price, and then sell the resulting residue gas and NGLs or NGL products at index related prices. Under percentage-of-index arrangements, we purchase natural gas from producers at a fixed percentage of the index price for the natural gas they produce and subsequently sell the residue gas and NGLs or NGL products at market prices. Under both of these types of contracts our revenues and total segment margin increase or decrease, whichever is applicable, as the price of natural gas and NGLs fluctuates. For a detailed discussion of these contracts, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations Our Contracts."

We may not successfully balance our purchases of natural gas and our sales of residue gas and NGLs, which increases our exposure to commodity price risks.

We may not be successful in balancing our purchases and sales. In addition, a producer could fail to deliver promised volumes or deliver in excess of contracted volumes, or a purchaser could purchase less than contracted volumes. Any of these actions could cause our purchases and sales not to be balanced. If our purchases and sales are not balanced, we will face increased exposure to commodity price risks and could have increased volatility in our operating income.

Our construction of new assets or the expansion of existing assets may not result in revenue increases and is subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our results of operations and financial condition.

One of the ways we may grow our business is through the construction of new midstream assets or the expansion of existing systems such as our Badlands expansion project. The construction of additions or modifications to our existing systems, and the construction of new midstream assets involve numerous regulatory, environmental, political and legal uncertainties beyond our control and require the expenditure of significant amounts of capital. If we undertake these projects, they may not be completed on schedule at the budgeted cost, or at all. Moreover, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we expand a new pipeline, the construction may occur over an extended period of time, and we will not receive any material increases in revenues until the project is completed. Moreover, we may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize. Since we are not engaged in the exploration for and development of oil and natural gas reserves, we often do not have access to estimates of potential reserves in an area prior to constructing facilities in such area. To the extent we rely on estimates of future production in our decision to construct additions to our systems, such estimates may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of future production. As a result, new facilities may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our results of operations and financial condition.

A change in the characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

As a natural gas gatherer and intrastate pipeline company, we generally are exempt from Federal Energy Regulatory Commission, or FERC, regulation under the Natural Gas Act of 1938, or NGA, but FERC regulation still affects our business and the market for our products. FERC's policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on open access transportation, ratemaking, capacity release, and market center promotion, indirectly affect intrastate markets. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, we cannot assure you that FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity. In addition, the distinction between FERC-regulated transmission service and federally unregulated gathering services is the subject of regular litigation, so, in such a circumstance, the classification and regulation of some of our gathering facilities may be subject to change based on future determinations by the FERC and the courts.

Other state and local regulations also affect our business. Our gathering lines are subject to ratable take and common purchaser statutes in states in which we operate. Ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes restrict our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas. Federal law leaves any economic regulation of natural gas gathering to the states. States in which we operate have adopted complaint based regulation of natural gas gathering activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination. While our proprietary gathering lines currently are subject to limited state regulation, there is a risk that state laws will be changed, which may give producers a stronger basis to challenge proprietary status of a line, or the rates, terms and conditions of a gathering line providing transportation service.

We may incur significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental regulations or an accidental release of hazardous substances into the environment.

Our operations are subject to stringent and complex federal, state and local environmental laws and regulations. These include, for example, (i) the federal Clean Air Act and comparable state laws and regulations that impose obligations related to air emissions, (ii) the federal Resource Conservation and Recovery Act, or RCRA, and comparable state laws that impose requirements for the discharge of waste from our facilities and (iii) the Comprehensive Environmental, Response Compensation and Liability Act of 1980, or CERCLA, also known as "Superfund," and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent waste for disposal. Failure to comply with these laws and regulations or newly adopted laws or regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental statutes, including CERCLA and analogous state laws and regulations, impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other waste products into the environment.

There is inherent risk of the incurrence of environmental costs and liabilities in our business due to our handling of natural gas and other petroleum products, air emissions related to our operations, and historical industry operations and waste disposal practices. For example, an accidental release from one of our pipelines or processing facilities could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage, and fines or penalties for related violations of environmental laws or regulations. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may not be able to recover these costs from insurance.

If we do not make acquisitions on economically acceptable terms, our future growth will be limited.

Our ability to grow depends on our ability to make acquisitions that result in an increase in the cash generated from operations per unit. If we are unable to make these accretive acquisitions either because we are: (1) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (2) unable to obtain financing for these acquisitions on economically acceptable terms, or (3) outbid by competitors, then our future growth and ability to increase distributions will be limited. Furthermore, even if we do make acquisitions that we believe will be accretive, these acquisitions may nevertheless result in a decrease in the cash generated from operations per unit.

Any acquisition, including our recent Bakken acquisition, involves potential risks, including, among other things:

- mistaken assumptions about revenues and costs, including synergies;
- an inability to integrate successfully the businesses we acquire;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from the seller;
- the diversion of management's attention from other business concerns;
- unforeseen difficulties operating in new product areas or new geographic areas; and
- customer or key employee losses at the acquired businesses.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and you will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

Our acquisition strategy is based, in part, on our expectation of ongoing divestitures of midstream assets by large industry participants. A material decrease in such divestitures would limit our opportunities for future acquisitions and could adversely affect our operations and cash flows available for distribution to our unitholders.

If we are unable to obtain new rights-of-way or the cost of renewing existing rights-of-way increases, then we may be unable to fully execute our growth strategy and our cash flows could be adversely affected.

The construction of additions to our existing gathering assets may require us to obtain new rights-of-way prior to constructing new pipelines. We may be unable to obtain such rights-of-way to connect new natural gas supplies to our existing gathering lines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new rights-of-way or to renew existing rights-of-way. If the cost of obtaining new rights-of-way or renewing existing rights-of-way increases, then our cash flows could be adversely affected.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. If a significant accident or event occurs that is not fully insured, our operations and financial results could be adversely affected.

Our operations are subject to the many hazards inherent in the gathering, treating, processing and fractionation of natural gas and NGLs, including:

damage to pipelines, related equipment and surrounding properties caused by tornadoes, floods, fires and other natural disasters and acts of terrorism;

inadvertent damage from construction and farm equipment;

leaks of natural gas, NGLs and other hydrocarbons or losses of natural gas or NGLs as a result of the malfunction of measurement equipment or facilities at receipt or delivery points;

fires and explosions; and

other hazards, including those associated with high-sulfur content, or sour gas, that could also result in personal injury and loss of life, pollution and suspension of operations.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of our related operations. A natural disaster or other hazard affecting the areas in which we operate could have a material adverse effect on our operations. We are not fully insured against all risks incident to our business. In accordance with typical industry practice, we do not have any property insurance on any of our underground pipeline systems that would cover damage to the pipelines. We are not insured against all environmental accidents that might occur, other than those considered to be sudden and accidental. In addition, we do not have business interruption insurance. If a significant accident or event occurs that is not fully insured, it could adversely affect our operations and financial condition.

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

Our credit facility contains various covenants limiting our ability to incur indebtedness, grant liens, engage in transactions with affiliates, make distributions to our unitholders and capitalize on acquisition or other business opportunities. It also contains covenants requiring us to maintain certain financial ratios and tests. We are prohibited from making any distribution to unitholders if such distribution would cause a default or an event of default under our credit facility. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions. Upon completion of this offering, we expect our total outstanding long-term indebtedness to be approximately $29.5 million, all under our senior secured revolving credit facility. Payments of principal and interest on the indebtedness will reduce the cash available for distribution on our units. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Description of Our Indebtedness" for a discussion of our credit facility.

Due to our lack of asset diversification, adverse developments in our midstream operations would reduce our ability to make distributions to our unitholders.

We rely exclusively on the revenues generated from our gathering, dehydration, treating, processing, fractionation and compressor services businesses, and as a result, our financial condition depends upon prices of, and continued demand for, natural gas and NGLs. Due to our lack of diversification in asset type, an adverse development in one of these businesses would have a significantly greater impact on our financial condition and results of operations than if we maintained more diverse assets.

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

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

Our hedging activities may have a material adverse effect on our earnings, profitability, cash flows and financial condition.

We utilize derivative financial instruments related to the future price of natural gas and may utilize such instruments related to the future price of NGLs with the intent of reducing volatility in our cash flows due to fluctuations in commodity prices. While our hedging activities are designed to reduce commodity price risk, we remain exposed to fluctuations in commodity prices to some extent.

The extent of our commodity price exposure is related largely to the effectiveness and scope of our hedging activities. For example, the derivative instruments we utilize are based on posted market prices, which may differ significantly from the actual natural gas prices or NGLs prices that we realize in our operations. Furthermore, our hedges relate to only a portion of the volume of our expected sales and, as a result, we will continue to have direct commodity price exposure to the unhedged portion. Our actual future sales may be significantly higher or lower than we estimate at the time we enter into derivative transactions for such period. If the actual amount is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount is lower than the amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, resulting in a substantial diminution of our liquidity.

As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows. In addition, our hedging activities are subject to the risks that a counterparty may not perform its obligation under the applicable derivative instrument, the terms of the derivative instruments are imperfect, and our hedging procedures may not be properly followed. We cannot assure you that the steps we take to monitor our derivative financial instruments will detect and prevent violations of our risk management policies and procedures, particularly if deception or other intentional misconduct is involved.

Terrorist attacks, and the threat of terrorist attacks, have resulted in increased costs to our business. Continued hostilities in the Middle East or other sustained military campaigns may adversely impact our results of operations.

The long-term impact of terrorist attacks, such as the attacks that occurred on September 11, 2001, and the threat of future terrorist attacks, on the energy transportation industry in general, and on us in particular, is not known at this time. Increased security measures taken by us as a precaution against possible terrorist attacks have resulted in increased costs to our business. Uncertainty surrounding continued hostilities in the Middle East or other sustained military campaigns may affect our operations in unpredictable ways, including disruptions of crude oil supplies and markets for refined products, and the possibility that infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror.

Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital.

Risks Inherent in an Investment in Us

Harold Hamm controls our general partner, which has sole responsibility for conducting our business and managing our operations. Affiliates of Harold Hamm and our general partner have conflicts of interest and limited fiduciary duties, which may permit them to favor their own interests to your detriment.

Following the offering, the Hamm Parties and members of our management will indirectly own a 53.0% limited partner interest in us. In addition, Harold Hamm controls our general partner. Conflicts of interest may arise between Harold Hamm, the Harold Hamm DST Trust and the Harold Hamm HJ Trust, which we collectively refer to as the Hamm Trusts, and their affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. As a result of these conflicts, the 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:

- Harold Hamm and the Hamm Trusts own Continental Resources; neither our partnership agreement nor any other agreement requires Continental Resources to pursue a business strategy that favors us;
- our general partner is allowed to take into account the interests of parties other than us, in resolving conflicts of interest;
- our general partner has limited its liability and reduced its fiduciary duties, and has also restricted the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;
- our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuance of additional limited partner securities, and reserves, each of which can affect the amount of cash that is distributed to 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 controls the enforcement of obligations owed to us by our general partner and its affiliates; and
- our general partner decides whether to retain separate counsel, accountants, or others to perform services for us.

Please read "Conflicts of Interest and Fiduciary Duties."

Unitholders have limited voting rights and limited ability to influence our operations and activities.

Unitholders have only limited voting rights on matters affecting our operations and activities and, therefore, limited ability to influence management's decisions regarding our business. Unitholders did not select our general partner or elect the board of directors of our general partner and effectively have no right to select our general partner or elect its board of directors in the future.

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 the 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 be voted on any matter. In addition, the partnership agreement 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. Please read "The Partnership Agreement Voting Rights."

Our general partner determines the cost reimbursement and fees payable to it from us; such payments may be substantial and could reduce our cash available for distribution to you.

Payments to our general partner may be substantial and will reduce the amount of available cash for distribution to unitholders. We will reimburse our general partner for the provision by it and its affiliates of various general and administrative services for our benefit, including the salaries and costs of employee benefits for employees of the general partner that provide services to us. Our general partner determines the amount of expenses allocable to us. There is no cap on the amount that may be paid or reimbursed to our general partner for compensation or expenses incurred on our behalf. Our general partner and its affiliates also may provide us other services for which we will be charged fees as determined by our general partner.

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 limited partner;

- provides that our general partner is entitled to make other decisions in "good faith" if it reasonably believes that the decision is in our best interests;

- generally provides 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 and that, in determining whether a transaction or resolution is "fair and reasonable," our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us; and

- provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that such person's conduct was criminal.

In order to become a limited partner of our partnership, a common unitholder is required to agree to be bound by the provisions in the partnership agreement, including the provisions discussed above. Please read "Conflicts of Interest and Fiduciary Duties Fiduciary Duties."

Harold Hamm and Continental Resources may engage in limited competition with us.

Harold Hamm and Continental Resources and their affiliates may engage in limited competition with us. Pursuant to the omnibus agreement entered into in connection with our initial public offering, Harold Hamm has agreed that neither he nor any of his affiliates (including Continental Resources) will engage in, whether by acquisition, construction, investment in debt or equity interests of any person or otherwise, the business of gathering, treating, processing and transportation of natural gas in North America, the transportation and fractionation of NGLs in North America, and constructing, buying or selling any assets related to the foregoing businesses. This restriction does not apply to:

- any business that is primarily related to the exploration for and production of oil or natural gas, including the sale and marketing of oil and natural gas derived from such exploration and production activities;
- any business conducted by Harold Hamm or his affiliates as of the date of the omnibus agreement;
- the purchase and ownership of not more than five percent of any class of securities of any entity engaged in any restricted business (but without otherwise participating in the activities of such entity);
- any business that Harold Hamm or his affiliates acquires or constructs that has a fair market value or construction cost, as applicable, of less than $5.0 million;
- any business that Harold Hamm or his affiliates acquires or constructs that has a fair market value or construction cost, as applicable, of $5.0 million or more if we have been offered the opportunity to purchase the business for the fair market value or construction cost, as applicable, and we decline to do so with the concurrence of the conflicts committee of our general partner; and
- any business conducted by Harold Hamm or his affiliates with the approval of the conflicts committee.

These non-competition obligations will terminate on the first to occur of the following events:

- the first day on which the Hamm Parties no longer control us;
- the death of Harold Hamm; and
- February 15, 2010, the fifth anniversary of the closing of our initial public offering.

For a description of the non-competition provisions of the omnibus agreement, please read "Certain Relationships and Related Party Transactions Agreements with Harold Hamm and His Affiliates Omnibus Agreement Non-Competition."

Even if unitholders are dissatisfied, they cannot remove our general partner without its consent.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders did not elect our general partner or the board of directors of our general partner and will have no right to elect our general partner or the board of directors of our general partner on an annual or other continuing basis. The board of directors of our general partner is chosen by the members of our general partner. Furthermore, if the unitholders were dissatisfied with the performance of our general partner, they would have little ability to remove our general partner. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

The unitholders will be unable initially to remove the general partner without its consent because the general partner and its affiliates will own sufficient units upon completion of the offering to be able to prevent removal. The vote of the holders of at least $66^2/_3\%$ of all outstanding units voting together as a single class is required to remove the general partner. Following the closing of this offering, the general partner and its affiliates will own 54.1% of the units outstanding. Also, if the general partner is removed without cause during the subordination period and units held by the general partner and its

affiliates are not voted in favor of that removal, all remaining subordinated units will automatically convert into common units and any existing arrearages on the common units will be extinguished. A removal of the general partner under these circumstances would adversely affect the common units by prematurely eliminating their distribution and liquidation preference over the subordinated units, which would otherwise have continued until we had met certain distribution and performance tests. Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding the general partner liable for actual fraud, gross negligence, or willful or wanton misconduct in its capacity as our general partner. Cause does not include most cases of charges of poor management of the business, so the removal of the general partner because of the unitholder's dissatisfaction with the general partner's performance in managing our partnership would most likely result in the termination of the subordination period.

Furthermore, 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 the general partner, its affiliates, their transferees, and persons who acquired such units with the prior approval of the board of directors of the general partner's 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.

The control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of the members of our general partner from transferring their respective membership interests in our general partner to a third party. The new members of our general partner would then be in a position to replace the board of directors of our general partner with their own choices and to control the decisions taken by the board of directors.

We do not have our own officers and employees and rely solely on the officers and employees of our general partner and its affiliates to manage our business and affairs.

We do not have our own officers and employees and rely solely on the officers and employees of our general partner and its affiliates to manage our business and affairs. We can provide no assurance that the general partner will continue to provide us the officers and employees that are necessary for the conduct of our business nor that such provision will be on terms that are acceptable to us. Other than option agreements, neither we nor our general partner have entered into any employment agreements with any officers of our general partner. If the general partner fails to provide us with adequate personnel, our operations could be adversely impacted. Certain of our general partner's employees provide services to Continental Resources in connection with the operation of compression assets owned by Continental Resources. In addition, certain of the officers of our general partner, including the chief executive officer and chief financial officer, may also serve as officers and directors of affiliates of the general partner.

We may issue additional common units without your approval, which would dilute your existing ownership interests.

During the subordination period, our general partner, without the approval of our unitholders, may cause us to issue up to 1,360,000 additional common units. Our general partner may also cause us to issue an unlimited number of additional common units or other equity securities of equal rank with the common units, without unitholder approval, in a number of circumstances such as:

- the issuance of common units upon the exercise of the underwriters' over-allotment option;

- the issuance of common units in connection with acquisitions or capital improvements that increase cash flow from operations per unit on an estimated pro forma basis;
- issuances of common units to repay indebtedness, if the cost to service the indebtedness is greater than the distribution obligations associated with the units issued in connection with the repayment of the indebtedness;
- the conversion of subordinated units into common units;
- the conversion of units of equal rank with the common units into common units under some circumstances;
- in the event of a combination or subdivision of common units;
- issuances of common units under our employee benefit plans; or
- the conversion of the general partner interest and the incentive distribution rights into common units as a result of the withdrawal or removal of our general partner.

In addition, our partnership agreement does not prohibit the issuance by our subsidiaries of equity securities, which may effectively rank senior to the common units.

The issuance of additional common units or other equity securities of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us may decrease;
- the amount of cash available for distribution on each unit may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- the relative voting strength of each previously outstanding unit may be diminished;
- the market price of the common units may decline; and
- the ratio of taxable income to distributions may increase.

After the end of the subordination period, we may issue an unlimited number of limited partner interests of any type without the approval of our unitholders. Our partnership agreement does not give our unitholders the right to approve our issuance of equity securities ranking junior to the common units at any time.

Our general partner's discretion in determining the level of cash reserves may reduce the amount of available cash for distribution to you.

Our partnership agreement requires our general partner to deduct from operating surplus cash reserves that it establishes are necessary to fund our future operating expenditures. In addition, our partnership agreement also permits our general partner to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party, or to provide funds for future distributions to partners. These reserves will affect the amount of cash available for distribution to you.

Our general partner may cause us to borrow funds in order to make cash distributions, even where the purpose or effect of the borrowing benefits our general partner or its affiliates.

In some instances, our general partner may cause us to borrow funds in order to permit the payment of cash distributions. These borrowings are permitted even if the purpose and effect of the borrowing is to enable us to make a distribution on the subordinated units, to make incentive distributions, or to hasten the expiration of the subordination period.

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

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your units. At the completion of this offering, our general partner and its affiliates will own approximately 10.8% of the common units and, at the end of the subordination period, assuming no additional issuances of common units, our general partner and its affiliates will own approximately 54.1% of the common units. For additional information about this right, please read "The Partnership Agreement Limited Call Right."

You could be liable for any and all of our obligations if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. You could be liable for any and all of our obligations as if you were a general partner if:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state's partnership statute; or

- your right to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

For a discussion of the implications of the limitations of liability on a unitholder, please read "The Partnership Agreement Limited Liability."

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to you if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable for the obligations of the assignor to make contributions to the partnership that are known to the substituted limited partner at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Tax Risks to Common Unitholders

In addition to reading the following risk factors, you should read "Material Tax Consequences" for a more complete discussion of the expected material federal income tax consequences of owning and disposing of common units.

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 Internal Revenue Service, or IRS, treats us as a corporation or we become subject to entity level taxation for state tax purposes, it would substantially reduce the amount of cash available for distribution to you.

The anticipated after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35% and would likely pay state income tax at varying rates. Distributions to you would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to you would be substantially reduced. Therefore, our treatment as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of our common units.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity level taxation. In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity level taxation through the imposition of state income, franchise and other forms of taxation. If any of these states were to impose a tax on us, the cash available for distribution to you would be reduced. The partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution levels will be adjusted to reflect the impact of that law on us.

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

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the conclusions of our counsel expressed in this prospectus or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take. A court may not agree with all of our counsel's conclusions or positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

You may be required to pay taxes on income from us even if you do not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, you will be required to pay any federal income taxes and, in some cases, state and local income taxes on your share of our taxable income even if you receive no cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the tax liability that results from that income.

Tax gain or loss on disposition of common units could be more or less than expected.

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

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

Investment in common units by tax-exempt entities, such as individual retirement accounts (known as IRAs), other retirement plans and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file United States federal tax returns and pay tax on their share of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our common units.

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

Because we cannot match transferors and transferees of common units and because of other reasons, we will take depreciation and amortization positions that may not conform to all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns. For a further discussion of the effect of the depreciation and amortization positions we will adopt, please read "Material Tax Consequences Tax Consequences of Unit Ownership Section 754 Election."

The sale or exchange of 50% or more of our capital and profits interests within a 12-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a 12-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income. Please read "Material Tax Consequences Disposition of Common Units Constructive Termination" for a discussion of the consequences of our termination for federal income tax purposes.

Unitholders may be subject to state and local taxes and return filing requirements.

In addition to federal income taxes, you will likely be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property, even if you do not live in any of those jurisdictions. You will likely be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, you may be subject to penalties for failure to comply with those requirements. We own assets and do business in North Dakota, Wyoming, Oklahoma, Texas, Mississippi and Montana. Each of these states, other than Texas and Wyoming, currently imposes a personal income tax as well as an income tax on corporations and other entities. As we make acquisitions or expand our business, we may own assets or do business in additional states that impose a personal income tax. It is your responsibility to file all United States federal, foreign, state and local tax returns. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in the common units.

USE OF PROCEEDS

We expect to receive aggregate net proceeds of approximately $64.2 million from (a) the sale of 1,600,000 common units offered by this prospectus and after deducting underwriting discounts and commissions and other offering expenses, and (b) our general partner's proportionate capital contribution. We intend to use all of the proceeds from this offering to repay a portion of the borrowings outstanding under our senior secured revolving credit facility incurred to fund the Bakken acquisition. We intend to use net proceeds, if any, from the exercise of the underwriters' over-allotment option to further repay borrowings outstanding under our credit facility.

As of September 30, 2005, total borrowings under our credit facility were approximately $93.7 million, with a weighted-average interest rate of 6.6%. Our credit facility matures in February 2008. Substantially all of the outstanding indebtedness under our credit facility was incurred to fund the Bakken acquisition.

CAPITALIZATION

The following table sets forth our cash and cash equivalents and our capitalization as of September 30, 2005 on:

- a historical basis; and
- on a pro forma basis to reflect the sale of common units in this offering, our general partner's proportionate capital contribution and the application of the net proceeds we expect to receive in the offering as described under "Use of Proceeds."

We derived this table from, and it should be read in conjunction with and is qualified in its entirety by reference to, the historical and pro forma financial statements and the accompanying notes included elsewhere in this prospectus. You should also read this table in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations."

	As of September 30, 2005	
	Historical	Pro Forma for this Offering
	(unaudited) (in thousands)	
Cash and cash equivalents	$ 6,816	$ 6,816
Total debt	$ 93,700	$ 29,520
Partners' capital:		
Common units	45,585	108,401
Subordinated units	25,186	25,186
General partner interest	1,040	2,404
Unearned compensation	(324)	(324)
Total partners' capital	71,487	135,667
Total capitalization	$ 165,187	$ 165,187

PRICE RANGE OF COMMON UNITS AND DISTRIBUTIONS

Our common units are quoted and traded on the NASDAQ National Market under the symbol "HLND." Our common units began trading on February 10, 2005 at an initial public offering price of $22.50 per common unit. The following table shows the low and high sales prices per common unit, as reported by the NASDAQ National Market, for the periods indicated. Distributions are shown in the quarter for which they were paid. For each quarter, an identical cash distribution was paid on all outstanding subordinated units.

	Low	High	Cash Distribution Per Unit
2005:			
Fourth quarter (through November 15, 2005)	$ 37.25	$ 46.47	$ (1)
Third quarter	34.58	46.22	0.5125(2)
Second quarter	31.17	37.32	0.4625
First quarter (from February 10, 2005)	27.50	35.00	0.2250(3)

(1) The cash distribution for this period has not been declared or paid.

(2) This cash distribution was paid on November 14, 2005.

(3) Reflects the pro rata portion of the $0.45 minimum quarterly distribution per unit, representing the period from the February 15, 2005 closing of our initial public offering through March 31, 2005.

The last reported sale price of the common units on the NASDAQ National Market on November 15, 2005 was $41.77. As of October 7, 2005, there were approximately 3,100 holders of record of our common units.

OUR CASH DISTRIBUTION POLICY AND RESTRICTIONS ON DISTRIBUTIONS

General

Rationale for Our Cash Distribution Policy. Our partnership agreement requires us to distribute all of our available cash quarterly. This cash distribution policy reflects a basic judgment that our unitholders will be better served by our distributing our cash available after expenses and reserves rather than retaining it. Because we believe we will generally finance any capital investments from external financing sources, we believe that our investors are best served by our distributing all of our available cash. Because we are not subject to an entity-level federal income tax, we have more cash to distribute to you than would be the case were we subject to tax.

Limitations on Cash Distributions and Our Ability to Change Our Cash Distribution Policy. There is no guarantee that unitholders will receive quarterly distributions from us. Our distribution policy is subject to certain restrictions and may be changed at any time, including:

- Our distribution policy is subject to restrictions on distributions under our credit facility. Specifically, the agreement related to our credit facility contains material financial tests and covenants that we must satisfy. These financial tests and covenants are described in this prospectus under the caption "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources." Should we be unable to satisfy these restrictions under our credit facility, we would be prohibited from making cash distributions to you notwithstanding our stated cash distribution policy.

- Our board of directors will have the authority to establish reserves for the prudent conduct of our business and for future cash distributions to our unitholders, and the establishment of those reserves could result in a reduction in cash distributions to you from levels we currently anticipate pursuant to our stated distribution policy.

- Even if our cash distribution policy is not modified or revoked, the amount of distributions we pay under our cash distribution policy and the decision to make any distribution is determined by of our general partner, taking into consideration the terms of our partnership agreement.

- Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to you if the distribution would cause our liabilities to exceed the fair value of our assets.

- We may lack sufficient cash to pay distributions to our unitholders due to increases in our general and administrative expense, principal and interest payments on our outstanding debt, tax expenses, working capital requirements and anticipated cash needs.

- While our partnership agreement requires us to distribute all of our available cash, our partnership agreement, including provisions requiring us to make cash distributions contained therein, may be amended. Although during the subordination period, with certain exceptions, our partnership agreement may not be amended without the approval of the public common unitholders, our partnership agreement can be amended with the approval of a majority of the outstanding common units, voting as a class (including common units held by affiliates of our general partner) after the subordination period has ended.

Our Cash Distribution Policy May Limit Our Ability to Grow. Because we distribute all of our available cash, our growth may not be as fast as businesses that reinvest their available cash to expand ongoing operations.

Our Ability to Grow is Dependent on Our Ability to Access External Expansion Capital. We expect that we will distribute all of our available cash to our unitholders. As a result, we expect that we will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. As a result, to the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow. In addition, to the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level, which in turn may reduce the available cash that we have to distribute on each unit. The incurrence of additional debt to finance our growth strategy would result in increased interest expense, which in turn may reduce the available cash that we have to distribute to our unitholders.

Distributions of Available Cash

General. Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash to unitholders of record on the applicable record date.

Definition of Available Cash. Available cash, for any quarter, consists of all cash on hand at the end of that quarter:

- less the amount of cash reserves established by our general partner to:
  - provide for the proper conduct of our business;
  - comply with applicable law, any of our debt instruments or other agreements; or
  - provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters;
- plus all cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter. Working capital borrowings are generally borrowings that are made under our credit facility and in all cases are used solely for working capital purposes or to pay distributions to unitholders.

Minimum Quarterly Distribution. Common unitholders are entitled under our partnership agreement to receive a quarterly distribution of $0.45 per unit, or $1.80 per year, prior to any distribution on the subordinated units to the extent we have sufficient cash from our operations after establishment of cash reserves and payment of fees and expenses, including payments to our general partner. Our general partner has the authority to determine the amount of our available cash for any quarter. This determination, as well as all determinations made by the general partner, must be made in good faith. Our partnership agreement provides that in order for a determination or other action to be in good faith, the person or persons making such determination or taking or declining to take such other action must reasonably believe that the determination or other action is in the best interests of the partnership, unless the context otherwise requires. For a discussion of our general partner's fiduciary duties, please read "Conflicts of Interest and Fiduciary Duties Fiduciary Duties." However, there is no guarantee that we will pay the minimum quarterly distribution on the common units in any quarter, and we will be prohibited from making any distributions to unitholders if it would cause an event of default, or an event of default is existing, under our credit agreement. For a discussion of the restrictions in our credit agreement that may restrict our ability to make distributions, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources."

Operating Surplus and Capital Surplus

General. All cash distributed to unitholders is characterized as either "operating surplus" or "capital surplus." Our partnership agreement requires that we distribute available cash from operating surplus differently than available cash from capital surplus.

Operating Surplus. Operating surplus consists of:

- our cash balance of $3.1 million on the closing date of our initial public offering; plus
- $7.7 million (as described below); plus
- all of our cash receipts since our initial public offering, excluding cash from borrowings that are not working capital borrowings, sales of equity and debt securities and sales or other dispositions of assets outside the ordinary course of business; plus
- working capital borrowings made after the end of a quarter but before the date of determination of operating surplus for the quarter; less
- all of our operating expenditures since our initial public offering, including the repayment of working capital borrowings, but not the repayment of other borrowings, and including maintenance capital expenditures; less
- the amount of cash reserves established by our general partner to provide funds for future operating expenditures.

As described above, maintenance capital expenditures reduce operating surplus, from which we pay the minimum quarterly distribution, but expansion capital expenditures do not. Maintenance capital expenditures represent capital expenditures made to replace partially or fully depreciated assets to maintain the existing operating capacity of our assets and to extend their useful lives, or other capital expenditures that are incurred in maintaining existing system volumes and related cash flows. Expansion capital expenditures represent capital expenditures made to expand or increase the efficiency of the existing operating capacity of our assets. Expansion capital expenditures include expenditures that facilitate an increase in volumes within our operations, whether through construction or acquisition. Expenditures that reduce our operating costs will be considered expansion capital expenditures only if the reduction in operating expenses exceeds cost reductions typically resulting from routine maintenance. We treat costs for repairs and minor renewals to maintain facilities in operating condition and that do not extend the useful life of existing assets as operations and maintenance expenses as we incur them. Our management has the discretion to determine how to allocate a capital expenditure for the acquisition or expansion of our assets between maintenance capital expenditures and expansion capital expenditures.

Capital Surplus. Capital surplus consists of:

- borrowings other than working capital borrowings;
- sales of our equity and debt securities; and
- sales or other dispositions of assets for cash, other than inventory, accounts receivable and other current assets sold in the ordinary course of business or as part of normal retirements or replacement of assets.

Characterization of Cash Distributions. Our partnership agreement requires that we treat all available cash distributed as coming from operating surplus until the sum of all available cash distributed since we began operations equals the operating surplus as of the most recent date of determination of available cash. Our partnership agreement requires that we treat any amount distributed in excess of operating surplus, regardless of its source, as capital surplus. As reflected above, operating surplus includes $7.7 million in addition to our cash balance on the closing date of our initial public offering, cash receipts from our operations and cash from working capital borrowings. This amount does not reflect actual cash on hand at the closing of our initial public offering that is available for distribution to our unitholders. Rather, it is a provision that will enable us, if we choose, to distribute as operating surplus up to $7.7 million of cash we receive in the future from non-operating sources, such as asset sales, issuances of securities, and long-term borrowings, that would otherwise be

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distributed as capital surplus. We do not anticipate that we will make any distributions from capital surplus.

Subordination Period

General. Our partnership agreement provides that, during the subordination period (which we define below and in Appendix A), the common units have the right to receive distributions of available cash from operating surplus each quarter in an amount equal to the minimum quarterly distribution of $0.45 per common unit plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. These units are deemed subordinated because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received the minimum quarterly distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The purpose of the subordinated units is to increase the likelihood that during the subordination period there will be available cash to be distributed on the common units.

Subordination Period. The subordination period will extend until the first day of any quarter beginning after March 31, 2010 that each of the following tests are met:

- distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equaled or exceeded the minimum quarterly distribution for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date;

- the "adjusted operating surplus" (as defined below) generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum of the minimum quarterly distributions on all of the outstanding common units and subordinated units during those periods on a fully diluted basis and the related distribution on the 2% general partner interest during those periods; and

- there are no arrearages in payment of the minimum quarterly distribution on the common units.

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

- the subordination period will end and each subordinated unit will immediately convert into one common unit;

- any existing arrearages in payment of the minimum quarterly distribution on the common units will be extinguished; and

- the general partner will have the right to convert its general partner interest and its incentive distribution rights into common units or to receive cash in exchange for those interests.

Early Conversion of Subordinated Units. If the tests for ending the subordination period are satisfied for any three consecutive four-quarter periods ending on or after March 31, 2008, 25% of the subordinated units will convert into an equal number of common units. Similarly, if those tests are also satisfied for any three consecutive four-quarter periods ending on or after March 31, 2009, an additional 25% of the subordinated units will convert into an equal number of common units. The second early conversion of subordinated units may not occur, however, until at least one year following the end of the period for the first early conversion of subordinated units.

Adjusted Operating Surplus. Adjusted operating surplus is intended to reflect the cash generated from operations during a particular period and therefore excludes net increases in working capital borrowings and net drawdowns of reserves of cash generated in prior periods. Adjusted operating surplus consists of:

- operating surplus generated with respect to that period; less
- any net increase in working capital borrowings with respect to that period; less
- any net decrease in cash reserves for operating expenditures with respect to that period not relating to an operating expenditure made with respect to that period; plus
- any net decrease in working capital borrowings with respect to that period; plus
- any net increase in cash reserves for operating expenditures with respect to that period required by any debt instrument for the repayment of principal, interest or premium.

Distributions of Available Cash from Operating Surplus during the Subordination Period

Our partnership agreement requires that we make distributions of available cash from operating surplus for any quarter during the subordination period in the following manner:

- *first*, 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding common unit an amount equal to the minimum quarterly distribution for that quarter;
- *second*, 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding common unit an amount equal to any arrearages in payment of the minimum quarterly distribution on the common units for any prior quarters during the subordination period;
- *third*, 98% to the subordinated unitholders, pro rata, and 2% to the general partner, until we distribute for each subordinated unit an amount equal to the minimum quarterly distribution for that quarter; and
- *thereafter*, in the manner described in "General Partner Interest and Incentive Distribution Rights" below.

Distributions of Available Cash from Operating Surplus after the Subordination Period

Our partnership agreement requires that we make distributions of available cash from operating surplus for any quarter after the subordination period in the following manner:

- *first*, 98% to all unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding unit an amount equal to the minimum quarterly distribution for that quarter; and
- *thereafter*, in the manner described in "General Partner Interest and Incentive Distribution Rights" below.

General Partner Interest and Incentive Distribution Rights

Our partnership agreement provides that our general partner is entitled to 2% of all distributions that we make prior to our liquidation. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its 2% general partner interest. The general partner's 2% interest will be reduced if we issue additional units in the future and our general partner does not contribute a proportionate amount of capital to us to maintain its 2% general partner interest.

Incentive distribution rights represent the right to receive an increasing percentage of quarterly distributions of available cash from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. Our general partner currently holds the incentive distribution rights, but may transfer these rights separately from its general partner interest, subject to restrictions in the partnership agreement.

If for any quarter:

- we have distributed available cash from operating surplus to the common and subordinated unitholders in an amount equal to the minimum quarterly distribution; and

- we have distributed available cash from operating surplus on outstanding common units in an amount necessary to eliminate any cumulative arrearages in payment of the minimum quarterly distribution;

then, we will distribute any additional available cash from operating surplus for that quarter among the unitholders and the general partner in the following manner:

- *first*, 98% to all unitholders, pro rata, and 2% to the general partner, until each unitholder receives a total of $0.495 per unit for that quarter (the "first target distribution");

- *second*, 85% to all unitholders, pro rata, and 15% to the general partner, until each unitholder receives a total of $0.5625 per unit for that quarter (the "second target distribution");

- *third*, 75% to all unitholders, pro rata, and 25% to the general partner, until each unitholder receives a total of $0.675 per unit for that quarter (the "third target distribution"); and

- *thereafter*, 50% to all unitholders, pro rata, and 50% to the general partner.

In each case, the amount of the target distribution set forth above is exclusive of any distributions to common unitholders to eliminate any cumulative arrearages in payment of the minimum quarterly distribution. The percentage interests set forth above for our general partner include its 2% general partner interest and assume the general partner has not transferred its incentive distribution rights.

Percentage Allocations of Available Cash from Operating Surplus

The following table illustrates the percentage allocations of the additional available cash from operating surplus between the unitholders and our general partner up to the various target distribution levels. The amounts set forth under "Marginal Percentage Interest in Distributions" are the percentage interests of our general partner and the unitholders in any available cash from operating surplus we distribute up to and including the corresponding amount in the column "Total Quarterly Distribution," until available cash from operating surplus we distribute reaches the next target distribution level, if any. The percentage interests shown for the unitholders and the general partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests set forth below for our general partner include its 2% general partner interest and assume the general partner has contributed any additional capital required to maintain its 2% general partner interest and has not transferred its incentive distribution rights.

		Marginal Percentage Interest in Distributions	
	Total Quarterly Distribution Target Amount	Unitholders	General Partner

		Marginal Percentage Interest in Distributions	
Minimum Quarterly Distribution	$0.45	98%	2%
First Target Distribution	up to $0.495	98%	2%
Second Target Distribution	above $0.495 up to $0.5625	85%	15%
Third Target Distribution	above $0.5625 up to $0.675	75%	25%
Thereafter	above $0.675	50%	50%

Distributions from Capital Surplus

How Distributions from Capital Surplus Will Be Made. Our partnership agreement requires that we make distributions of available cash from capital surplus, if any, in the following manner:

- *first*, 98% to all unitholders, pro rata, and 2% to the general partner, until we distribute for each common unit that was issued in our initial public offering, an amount of available cash from capital surplus equal to the initial public offering price;

- *second*, 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute for each common unit, an amount of available cash from capital surplus equal to any unpaid arrearages in payment of the minimum quarterly distribution on the common units; and

- *thereafter*, we will make all distributions of available cash from capital surplus as if they were from operating surplus.

Effect of a Distribution from Capital Surplus. Our partnership agreement treats a distribution of capital surplus as the repayment of the initial unit price from the initial public offering, which is a return of capital. The initial public offering price less any distributions of capital surplus per unit is referred to as the "unrecovered initial unit price." Each time a distribution of capital surplus is made, the minimum quarterly distribution and the target distribution levels will be reduced in the same proportion as the corresponding reduction in the unrecovered initial unit price. Because distributions of capital surplus will reduce the minimum quarterly distribution, after any of these distributions are made, it may be easier for the general partner to receive incentive distributions and for the subordinated units to convert into common units. However, any distribution of capital surplus before the unrecovered initial unit price is reduced to zero cannot be applied to the payment of the minimum quarterly distribution or any arrearages.

Once we distribute capital surplus on a unit in an amount equal to the initial unit price, we will reduce the minimum quarterly distribution and the target distribution levels to zero. We will then make all future distributions from operating surplus, with 50% being paid to the holders of units and 50% to the general partner. The percentage interests shown for our general partner include its 2% general partner interest and assume the general partner has not transferred the incentive distribution rights.

Adjustment to the Minimum Quarterly Distribution and Target Distribution Levels

In addition to adjusting the minimum quarterly distribution and target distribution levels to reflect a distribution of capital surplus, if we combine our units into fewer units or subdivide our units into a greater number of units, we will proportionately adjust:

- the minimum quarterly distribution;

- target distribution levels;

- the unrecovered initial unit price;

- the number of common units issuable during the subordination period without a unitholder vote; and

- the number of common units into which a subordinated unit is convertible.

For example, if a two-for-one split of the common units should occur, the minimum quarterly distribution, the target distribution levels and the unrecovered initial unit price would each be reduced to 50% of its initial level, the number of common units issuable during the subordination period without unitholder vote would double and each subordinated unit would be convertible into two common units. We will not make any adjustment by reason of the issuance of additional units for cash or property.

In addition, if legislation is enacted or if existing law is modified or interpreted by a governmental taxing authority, so that we become taxable as a corporation or otherwise subject to taxation as an entity for federal, state or local income tax purposes, we will reduce the minimum quarterly distribution and the target distribution levels for each quarter by multiplying each distribution level by a fraction, the numerator of which is available cash for that quarter and the denominator of which is the sum of available cash for that quarter plus the general partner's estimate of our aggregate liability for the quarter for such income taxes payable by reason of such legislation or interpretation. To the extent that the actual tax liability differs from the estimated tax liability for any quarter, the difference will be accounted for in subsequent quarters.

Distributions of Cash Upon Liquidation

General. If we dissolve in accordance with the partnership agreement, we will sell or otherwise dispose of our assets in a process called liquidation. We will first apply the proceeds of liquidation to the payment of our creditors. We will distribute any remaining proceeds to the unitholders and the general partner, in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation.

The allocations of gain and loss upon liquidation are intended, to the extent possible, to entitle the holders of outstanding common units to a preference over the holders of outstanding subordinated units upon our liquidation, to the extent required to permit common unitholders to receive their unrecovered initial unit price plus the minimum quarterly distribution for the quarter during which liquidation occurs plus any unpaid arrearages in payment of the minimum quarterly distribution on the common units. However, there may not be sufficient gain upon our liquidation to enable the holders of common units to fully recover all of these amounts, even though there may be cash available for distribution to the holders of subordinated units. Any further net gain recognized upon liquidation will be allocated in a manner that takes into account the incentive distribution rights of the general partner.

Manner of Adjustments for Gain. The manner of the adjustment for gain is set forth in the partnership agreement. If our liquidation occurs before the end of the subordination period, we will allocate any gain to the partners in the following manner:

- *first*, to the general partner and the holders of units who have negative balances in their capital accounts to the extent of and in proportion to those negative balances;

- *second*, 98% to the common unitholders, pro rata, and 2% to the general partner, until the capital account for each common unit is equal to the sum of: (1) the unrecovered initial unit price; (2) the amount of the minimum quarterly distribution for the quarter during which our liquidation occurs; and (3) any unpaid arrearages in payment of the minimum quarterly distribution;

- *third*, 98% to the subordinated unitholders, pro rata, and 2% to the general partner until the capital account for each subordinated unit is equal to the sum of: (1) the unrecovered initial unit price; and (2) the amount of the minimum quarterly distribution for the quarter during which our liquidation occurs;

- *fourth*, 98% to all unitholders, pro rata, and 2% to the general partner, until we allocate under this paragraph an amount per unit equal to: (1) the sum of the excess of the first target distribution per unit over the minimum quarterly distribution per unit for each quarter of our existence; less (2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the minimum quarterly distribution per unit that we distributed 98% to the unitholders, pro rata, and 2% to the general partner, for each quarter of our existence;

fifth, 85% to all unitholders, pro rata, and 15% to the general partner, until we allocate under this paragraph an amount per unit equal to: (1) the sum of the excess of the second target distribution per unit over the first target distribution per unit for each quarter of our existence; less (2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the first target distribution per unit that we distributed 85% to the unitholders, pro rata, and 15% to the general partner for each quarter of our existence;

sixth, 75% to all unitholders, pro rata, and 25% to the general partner, until we allocate under this paragraph an amount per unit equal to: (1) the sum of the excess of the third target distribution per unit over the second target distribution per unit for each quarter of our existence; less (2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the second target distribution per unit that we distributed 75% to the unitholders, pro rata, and 25% to the general partner for each quarter of our existence; and

thereafter, 50% to all unitholders, pro rata, and 50% to the general partner.

The percentage interests set forth above for our general partner include its 2% general partner interest and assume the general partner has not transferred the incentive distribution rights.

If the liquidation occurs after the end of the subordination period, the distinction between common units and subordinated units will disappear, so that clause (3) of the second bullet point above and all of the third bullet point above will no longer be applicable.

Manner of Adjustments for Losses. If our liquidation occurs before the end of the subordination period, we will generally allocate any loss to the general partner and the unitholders in the following manner:

first, 98% to holders of subordinated units in proportion to the positive balances in their capital accounts and 2% to the general partner, until the capital accounts of the subordinated unitholders have been reduced to zero;

second, 98% to the holders of common units in proportion to the positive balances in their capital accounts and 2% to the general partner, until the capital accounts of the common unitholders have been reduced to zero; and

thereafter, 100% to the general partner.

If the liquidation occurs after the end of the subordination period, the distinction between common units and subordinated units will disappear, so that all of the first bullet point above will no longer be applicable.

Adjustments to Capital Accounts. We will make adjustments to capital accounts upon the issuance of additional units. In doing so, we will allocate any unrealized and, for tax purposes, unrecognized gain or loss resulting from the adjustments to the unitholders and the general partner in the same manner as we allocate gain or loss upon liquidation. In the event that we make positive adjustments to the capital accounts upon the issuance of additional units, we will allocate any later negative adjustments to the capital accounts resulting from the issuance of additional units or upon our liquidation in a manner which results, to the extent possible, in the general partner's capital account balances equaling the amount which they would have been if no earlier positive adjustments to the capital accounts had been made.

SELECTED HISTORICAL AND PRO FORMA FINANCIAL AND OPERATING DATA

The following table shows selected historical financial and operating data and pro forma financial data for the periods and as of the dates indicated. The selected historical financial data for the years ended December 31, 2001, 2002, 2003 and 2004 are derived from our audited financial statements. The selected historical financial data as of and for the year ended December 31, 2000 and the nine months ended September 30, 2004 and 2005 are derived from our unaudited financial statements. Our historical financial data for the periods prior to February 15, 2005 reflect the historical financial data for Continental Gas, Inc., our predecessor. The selected pro forma financial data as of September 30, 2005 and for the year ended December 31, 2004 and nine months ended September 30, 2005 are derived from our unaudited pro forma financial statements.

The unaudited pro forma balance sheet data give pro forma effect to this offering of common units and our general partner's proportionate capital contribution as if they had occurred on September 30, 2005. The unaudited pro forma summary of operations data give pro forma effect to the following transactions as if they had occurred on January 1, 2004:.

- the Bakken acquisition;
- borrowings under our amended credit facility to fund the Bakken acquisition;
- this offering of common units and our general partner's proportionate capital contribution; and
- our initial public offering of common units and the formation transactions related to our partnership.

The following table includes the non-GAAP financial measures of (1) EBITDA and (2) total segment margin, which consists of midstream segment margin and compression segment margin. We define EBITDA as net income (loss) plus interest expense, provision for income taxes and depreciation, amortization and accretion expense. We define midstream segment margin as revenue less midstream purchases. Midstream purchases include the following costs and expenses: cost of natural gas and NGLs purchased by us from third parties, cost of natural gas and NGLs purchased by us from affiliates, and costs of crude oil purchased by us from third parties. We define compression segment margin as the revenues derived from our compression segment. For a reconciliation of these non-GAAP financial measures to their most directly comparable financial measures calculated and presented in accordance with GAAP, please refer to the reconciliation following the table below.

Maintenance capital expenditures represent capital expenditures made to replace partially or fully depreciated assets to maintain the existing operating capacity of our assets and to extend their useful lives, or other capital expenditures that are incurred in maintaining existing system volumes and related cash flows. Expansion capital expenditures represent capital expenditures made to expand or increase the efficiency of the existing operating capacity of our assets. Expansion capital expenditures include expenditures that facilitate an increase in volumes within our operations, whether through construction or acquisition. Expenditures that reduce our operating costs will be considered expansion capital expenditures only if the reduction in operating expenses exceeds cost reductions typically resulting from routine maintenance. We treat costs for repairs and minor renewals to maintain facilities in operating condition and that do not extend the useful life of existing assets as operations and maintenance expenses as we incur them.

We derived the information in the following table from, and that information should be read together with and is qualified in its entirety by reference to, the historical and pro forma combined financial statements and the accompanying notes included elsewhere in this prospectus. The table should be read together with "Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Predecessor						Hiland Partners, LP (1)	Hiland Partners, LP Pro Forma	
	Year Ended December 31,					Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Year Ended December 31, 2004	Nine Months Ended September 30, 2005
	2000	2001	2002	2003	2004				
	(unaudited)					(unaudited)			
	(in thousands, except per unit and operating data)								
Summary of Operations Data:									
Total revenues	$ 35,977	$ 45,489	$ 35,228	$ 76,018	$ 98,296	$ 70,286	$ 98,306	$ 112,631	$ 116,955
Operating costs and expenses:									
Midstream purchases (exclusive of items shown separately below)	28,844	33,929	27,935	67,002	82,532	59,846	77,548	87,132	90,573
Operations and maintenance	2,681	3,002	3,509	3,714	4,933	3,624	5,083	7,013	6,762
Depreciation, amortization and accretion	1,986	2,072	2,370	3,304	4,127	3,003	6,924	9,866	10,902
Property impairment				1,535					
(Gain) loss on asset sales	(522)	(76)	(12)	34	(19)	(15)		(19)	
Bad debt			295						
General and administrative	613	688	730	770	1,082	680	1,539	1,179	1,793
Total operating costs and expenses	33,602	39,615	34,827	76,359	92,655	67,138	91,094	105,171	110,030
Operating income (loss)	2,375	5,874	401	(341)	5,641	3,148	7,212	7,460	6,925
Other income (expense):									
Interest expense	(573)	(350)	(185)	(473)	(702)	(508)	(766)	(1,329)	(1,609)
Amortization of deferred loan costs				(24)	(102)	(76)	(360)	(818)	(649)
Interest income and other	49	95	72	10	40	23	112	41	115
Total other income (expense)	(524)	(255)	(113)	(487)	(764)	(561)	(1,014)	(2,106)	(2,143)
Income (loss) from continuing operations	1,851	5,619	288	(828)	4,877	2,587	6,198	5,354	4,782
Discontinued operations, net	633	285	199	246	35	34			
Income (loss) before change in accounting principle	2,484	5,904	487	(582)	4,912	2,621	6,198	5,354	4,782
Cumulative effect of change in accounting principle				1,554					
Net income	$ 2,484	$ 5,904	$ 487	$ 972	$ 4,912	$ 2,621	$ 6,198	$ 5,354	$ 4,782

Net income per limited partner unit basic							$ 0.82	$ 0.62	$ 0.56
Net income per limited partner unit diluted							$ 0.82	$ 0.62	$ 0.55
Balance Sheet Data (at period end):									
Property and equipment, at cost, net	$ 19,462	$ 20,638	$ 23,722	$ 38,425	$ 37,075	$ 37,766	$ 116,239		$ 116,239
Total assets	25,302	25,435	28,058	47,840	49,175	46,774	186,551		186,551
Accounts payable affiliates	1,103	877	2,150	2,814	2,998	2,431	7,660		7,660
Long-term debt	5,839	2,975	3,491	14,571	12,643	12,750	93,700		29,520
Net equity/Partners' capital	14,376	20,280	20,767	21,739	24,510	22,219	71,487		135,667
Cash Flow Data:									
Net cash flow provided by (used in):									
Operating activities	$ 2,182	$ 6,432	$ 4,809	$ 4,464	$ 7,957	$ 6,911	$ 900		
Investing activities	1,322	(3,242)	(5,645)	(17,286)	(5,290)	(4,867)	(65,210)		
Financing activities	(3,661)	(2,865)	516	13,212	(2,946)	(2,257)	70,909		
Other Financial Data:									
Midstream segment margin	$ 7,133	$ 11,560	$ 7,293	$ 9,016	$ 15,764	$ 10,440	$ 17,746	$ 21,645	$ 23,034
Compression segment margin							3,012	3,854	3,348
Total segment margin	$ 7,133	$ 11,560	$ 7,293	$ 9,016	$ 15,764	$ 10,440	$ 20,758	$ 25,499	$ 26,382
EBITDA	$ 5,043	$ 8,326	$ 3,042	$ 4,773	$ 9,843	$ 6,208	$ 14,248	$ 17,367	$ 17,942
Maintenance capital expenditures	$ 268	$ 844	$ 1,826	$ 1,769	$ 1,693	$ 1,243	$ 1,462		
Expansion capital expenditures	1,050	2,339	3,244	14,900	3,474	3,474	1,308		
Discontinued operations	4	235	690	745	159	159			
Total capital expenditures	$ 1,322	$ 3,418	$ 5,760	$ 17,414	$ 5,326	$ 4,876	$ 2,770		
Operating Data:									
Natural gas sales (MMBtu/d)		24,117	26,599	37,701	40,560	40,730	43,044	44,080	49,523
NGL sales (Bbls/d)		881	950	895	1,133	1,095	1,561	1,436	2,419

(1) For the period ended February 14, 2005, these results reflect the historical results for Continental Gas, Inc., our predecessor.

The following table presents a reconciliation of the non-GAAP financial measures of (1) EBITDA to the GAAP financial measure of net income and (2) total segment margin (which consists of the sum of midstream segment margin and compression segment margin) to operating income, in each case, on a historical basis and pro forma for this offering and the application of the net proceeds for each of the periods indicated.

	Predecessor						Hiland Partners, LP	Hiland Partners, LP Pro Forma	
	Year Ended December 31,								
	2000	2001	2002	2003	2004	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Year Ended December 31, 2004	Nine Months Ended September 30, 2005
	(unaudited)	(audited)				(unaudited)			
	(in thousands)								
Reconciliation of EBITDA to Net Income:									
Net income	$ 2,484	$ 5,904	$ 487	$ 972	$ 4,912	$ 2,621	$ 6,198	$ 5,354	$ 4,782
Add:									
Depreciation, amortization and accretion	1,986	2,072	2,370	3,304	4,127	3,003	6,924	9,866	10,902
Amortization of deferred loan costs				24	102	76	360	818	649
Interest expense	573	350	185	473	702	508	766	1,329	1,609
EBITDA	$ 5,043	$ 8,326	$ 3,042	$ 4,773	$ 9,843	$ 6,208	$ 14,248	$ 17,367	$ 17,942
Reconciliation of Total Segment Margin to Operating Income (Loss):									
Operating income (loss)	$ 2,375	$ 5,874	$ 401	$ (341)	$ 5,641	$ 3,148	$ 7,212	$ 7,460	$ 6,925
Add:									
Operations and maintenance	2,681	3,002	3,509	3,714	4,933	3,624	5,083	7,013	6,762
Depreciation, amortization and accretion	1,986	2,072	2,370	3,304	4,127	3,003	6,924	9,866	10,902
Property impairment				1,535					
(Gain) loss on asset sales	(522)	(76)	(12)	34	(19)	(15)		(19)	
Bad debt			295						
General and administrative	613	688	730	770	1,082	680	1,539	1,179	1,793
Total segment margin	$ 7,133	$ 11,560	$ 7,293	$ 9,016	$ 15,764	$ 10,440	$ 20,758	$ 25,499	$ 26,382

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

You should read the following discussion of our financial condition and results of operations in conjunction with the historical and pro forma financial statements and notes thereto included elsewhere in this prospectus. For more detailed information regarding the basis of presentation for the following information, you should read the notes to the historical and pro forma financial statements included elsewhere in this prospectus.

Overview

We are a Delaware limited partnership formed in October 2004 to own and operate the assets that have historically been owned and operated by Continental Gas, Inc. and Hiland Partners, LLC.

Continental Gas, Inc. historically has owned all of our natural gas gathering, processing, treating and fractionation assets other than our Worland and Bakken gathering systems. Hiland Partners, LLC historically has owned our Worland gathering system, our compression services assets and the Bakken gathering system. Continental Gas, Inc. is our predecessor for accounting purposes. As a result, our historical financial statements for periods prior to February 15, 2005 are the financial statements of Continental Gas, Inc.

In connection with our initial public offering, the former owners of Continental Gas, Inc. and Hiland Partners, LLC and certain of our affiliates, including our general partner, contributed to us, all of the assets and operations of Continental Gas, Inc., other than a portion of its working capital assets, and substantially all of the assets and operations of Hiland Partners, LLC, other than a portion of its working capital assets and the assets related to the Bakken gathering system, in exchange for an aggregate of 720,000 common units and 4,080,000 subordinated units, a 2% general partner interest in us and all of our incentive distribution rights, which entitle the general partner to increasing percentages of the cash we distribute in excess of $0.495 per unit per quarter.

We completed our initial public offering of 2,300,000 common units on February 15, 2005, receiving net proceeds of $48.1 million. The proceeds from the public offering were used to (1) pay remaining offering costs of $2.2 million and deferred debt issuance costs of $0.6 million, (2) pay outstanding indebtedness of $22.9 million, (3) redeem $6.3 million of common units from an affiliate of Harold Hamm and the Hamm Trusts, and (4) make a $3.9 million distribution to the previous owners of Hiland Partners, LLC. We retained $12.2 million to replenish working capital.

Effective September 1, 2005, we consummated the Bakken acquisition pursuant to which we acquired the outstanding membership interests in Hiland Partners, LLC, an Oklahoma limited liability company, for approximately $92.7 million in cash, $35.0 million of which was used to retire outstanding Hiland Partners, LLC indebtedness. Hiland Partners, LLC's principal asset is the Bakken gathering system located in eastern Montana.

In this discussion and analysis of our financial condition and results of operations, pro forma information gives effect to our formation transactions and the Bakken acquisition (including indebtedness incurred to fund the acquisition) as if they had occurred on January 1, 2004.

We are engaged in gathering, compressing, dehydrating, treating, processing and marketing natural gas, fractionating NGLs and providing air compression and water injection services for oil and gas secondary recovery operations. Our operations are primarily located in the Mid-Continent and Rocky Mountain regions of the United States.

We manage our business and analyze and report our results of operations on a segment basis. Our operations are divided into two business segments:

Midstream Segment, which is engaged in gathering and processing of natural gas primarily in the Mid-Continent and Rocky Mountain regions. Within this segment, we also provide certain related services for compression, dehydrating, and treating of natural gas and the fractionation of NGLs. For the year ended December 31, 2004 and the nine months ended September 30, 2005, this segment generated approximately 84.9% and 87.3%, respectively, of our total segment margin on a pro forma basis.

Compression Segment, which is engaged in providing air compression and water injection services for oil and gas secondary recovery operations that are ongoing in North Dakota. For the year ended December 31, 2004 and the nine months ended September 30, 2005, this segment generated approximately 15.1% and 12.7%, respectively, of our total segment margin on a pro forma basis.

Our results of operations are determined primarily by five interrelated variables: (1) the volume of natural gas gathered through our pipelines; (2) the volume of natural gas processed; (3) the volume of NGLs fractionated; (4) the level and relationship of natural gas and NGL prices; and (5) our current contract portfolio. Because our profitability is a function of the difference between the revenues we receive from our operations, including revenues from the products we sell, and the costs associated with conducting our operations, including the costs of products we purchase, increases or decreases in our revenues alone are not necessarily indicative of increases or decreases in our profitability. To a large extent, our contract portfolio and the pricing environment for natural gas and NGLs will dictate increases or decreases in our profitability. Our profitability is also dependent upon prices and market demand for natural gas and NGLs, which fluctuate with changes in market and economic condition and other factors.

How We Evaluate Our Operations

Our management uses a variety of financial and operational measurements to analyze our segment performance. These measurements include the following: (1) natural gas and NGL sales volumes, throughput volumes and fuel consumption by our facilities; (2) total segment margin; (3) operations and maintenance expenses; (4) general and administrative expenses; and (5) EBITDA.

Volumes and Fuel Consumption. Natural gas and NGL sales volumes, throughput volumes and fuel consumption associated with our business are an important part of our operational analysis. We continually monitor volumes on our pipelines to ensure that we have adequate throughput to meet our financial objectives. It is important that we continually add new volumes to our gathering systems to offset or exceed the normal decline of existing volumes that are connected to those systems. The performance at our processing, fractionation and treating facilities is significantly influenced by the volumes of natural gas that flows through our systems. In addition, we monitor fuel consumption because it has an impact on the total segment margin realized from our midstream operations and our compression services operations.

Total Segment Margin. We view total segment margin as an important performance measure of the core profitability of our operations. We review total segment margin monthly for consistency and trend analysis.

With respect to our midstream segment, we define midstream segment margin as our revenue minus midstream purchases. Revenue includes revenue from the sale of natural gas, NGLs and NGL products resulting from our gathering, treating, processing and fractionation activities and fixed fees associated with the gathering of natural gas and the transportation and disposal of saltwater. Midstream purchases include the cost of natural gas, condensate and NGLs purchased by us from third parties and the cost for the transportation and fractionation of NGLs by third parties. Our midstream segment margin is impacted by our midstream contract portfolio, which is described in more detail below.

With respect to our compression segment, following the restructuring of our lease arrangement to become a service arrangement in connection with our initial public offering as described in " Items Impacting Comparability of Our Financial Results," our compression segment margin equals the fee we earn under our Compression Services Agreement with Continental Resources, Inc. for providing air compression and water injection services. The fee that we earn under this agreement is fixed so long as our facilities meet specified availability requirements, regardless of Continental Resources, Inc.'s utilization. As a result, our compression segment margin is dependent on our ability to meet their utilization levels. For a discussion of this agreement, please read " Our Contracts Compression Services Agreement."

Operations and Maintenance Expenses. Operations and maintenance expenses are costs associated with the operation of a specific asset. Direct labor, insurance, ad valorem taxes, repair and maintenance, utilities and contract services comprise the most significant portion of our operations and maintenance expenses. These expenses remain relatively stable independent of the volumes through our systems but fluctuate slightly depending on the activities performed during a specific period.

General and Administrative Expenses. Our general and administrative expenses include the cost of employee and officer compensation and related benefits, office lease and expenses, professional fees, information technology expenses, as well as other expenses not directly associated with our field operations.

Our general and administrative expenses have increased as a result of our becoming a public company. These expenses were approximately $1.2 million for 2004 and $1.8 million for the nine months ended September 30, 2005, on a pro forma basis. This increase was due to the cost of tax return preparations, accounting support services, filing annual and quarterly reports with the Securities and Exchange Commission, investor relations, directors' and officers' insurance and registrar and transfer agent fees.

In the omnibus agreement that we entered into in connection with our initial public offering, Continental Resources, Inc. agreed to provide the following services to us for two years, at the lower of Continental Resources, Inc.'s cost to provide the services or $50,000 per year:

- information technology support, including supplying our computer servers, repair services and electronic mail; and
- human resource functions, including locating and recruiting potential employees and assistance in complying with certain employment laws and regulations.

EBITDA. We define EBITDA as net income plus interest expense, provision for income taxes and depreciation, amortization and accretion expense. EBITDA is used as a supplemental financial measure by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness;
- our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing or capital structure; and

the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

EBITDA is also a financial measurement that, with certain negotiated adjustments, is reported to our lenders and is used as a gauge for compliance with some of our financial covenants under our credit facility. EBITDA should not be considered an alternative to net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP.

How We Manage Our Operations

Our management team uses a variety of tools to manage our business. These tools include: (1) flow and transaction monitoring systems; (2) producer activity evaluation and reporting; and (3) imbalance monitoring and control.

Flow and transaction monitoring systems. We utilize a customized system that tracks commercial activity on a daily basis at each of our gathering systems, processing plants and treating and fractionation facilities. We track and monitor inlet volumes to our facilities, fuel consumption, NGLs and NGL products extracted, condensate volumes and residue sales volumes. We also monitor daily operational throughput at our air compression and water injection facilities.

Producer activity evaluation and reporting. We monitor the producer drilling and completion activity in our primary areas of operation to identify anticipated changes in production and potential new well attachment opportunities. The continued connection of natural gas production to our gathering systems is critical to our business and directly impacts our financial performance. Through our relationship with Continental Resources, Inc., we receive weekly summaries of new drilling permits and completion reports filed with the state regulatory agencies that govern these activities on all of our gathering systems other than the Bakken gathering system. Producers that have dedicated acreage to our Bakken gathering system provide us with their projected annual drilling schedules, which are updated periodically. Additionally, our field personnel report the locations of new wells in their respective areas and anticipated changes in production volumes to supply representatives and operating personnel at our corporate offices. These processes enhance our awareness of new well activity in our operating areas and allow us to be responsive to producers in connecting new volumes of natural gas to our pipelines.

Imbalance monitoring and control. We continually monitor volumes we deliver to pipelines and volumes nominated for sale on pipelines to ensure we remain within acceptable imbalance limits during a calendar month. We seek to reduce imbalances because of the inherent commodity risk that results when deliveries and sales of natural gas are not balanced concurrently.

Our Contracts

Because of the significant volatility of natural gas and NGL prices, our contract mix can have a significant impact on our profitability. In order to reduce our exposure to commodity price risk, we pursue arrangements under which we purchase natural gas from the producers at the wellhead at an index based price less a fixed fee to gather, dehydrate, compress, treat and/or process their natural gas, referred to as fee based arrangements or contracts, where market conditions permit. Actual contract terms are based upon a variety of factors, including natural gas quality, geographical location, the competitive environment at the time the contract is executed and customer requirements. Our contract mix and, accordingly, our exposure to natural gas and NGL prices, may change as a result of producer preferences, our expansion in regions where some types of contracts are more common and other market factors.

Our Natural Gas Sales Contracts

We sell natural gas on intrastate and interstate pipelines to marketing affiliates of natural gas pipelines, marketing affiliates of integrated oil companies and utilities. We typically sell natural gas on a monthly basis under index related pricing terms. In addition, as of September 30, 2005, we have forward sales contracts to (a) sell approximately 50,000 MMBtu of natural gas per month through December 2007 with weighted average fixed prices per MMBtu of $4.53, $4.47 and $4.49, respectively, for years 2005 through 2007 and (b) sell approximately 50,000 MMBtu of natural gas per month from October 2005 through December 2006 with weighted average fixed price per MMBtu of $9.52. All of our forward sales contracts relate to volumes from our Eagle Chief gathering system.

Our NGL Sales Arrangements

We sell NGLs and NGL products at the tailgate of our facilities to ONEOK Hydrocarbon, LP, SemStream, L.P., and a subsidiary of Kinder Morgan Energy Partners, L.P. We typically sell NGLs and NGL products on a monthly basis under index related pricing terms.

Our Natural Gas Purchase Contracts

With respect to our natural gas gathering, compression, dehydrating, treating, processing and marketing activities and our NGL fractionation activities, we contract under the following types of arrangements:

Percentage-of-proceeds arrangements. Under percentage-of-proceeds arrangements, we generally purchase natural gas from producers at the wellhead, gather, treat, and process the natural gas, in some cases fractionate the NGLs into NGL products, and then sell the resulting residue gas and NGLs or NGL products at index related prices. We remit to the producers either an agreed upon percentage of the proceeds or an index related price for the natural gas and the NGLs. Under these types of arrangements, our revenues and total segment margin correlate directly with the price of natural gas and NGLs. For the year ended December 31, 2004 and the nine months ended September 30, 2005, we purchased 33.0% and 45.4%, respectively, of our total volumes under these types of fee arrangements on a pro forma basis. The increase in percentage-of-proceeds arrangements is primarily due to the Bakken gathering system becoming operational on November 8, 2004. All of our contracts at the Bakken gathering system are percentage-of-proceed arrangements.

Percentage-of-index arrangements. Under percentage-of-index arrangements, we purchase natural gas from the producers at the wellhead at a price that is at a fixed percentage of the index price for the natural gas that they produce. We then gather, treat and process the natural gas, in some cases fractionate the NGLs into NGL products and then sell the residue gas and NGLs or NGL products pursuant to natural gas or NGL arrangements described above. Since under these types of arrangements our costs to purchase the natural gas from the producer is based on the price of natural gas, our total segment margin under these arrangements increases as the price of NGLs increase relative to the price of natural gas, and our total segment margin under these arrangements decreases as the price of natural gas increases relative to the price of NGLs. For the year ended December 31, 2004 and the nine months ended September 30, 2005, we purchased 31.7% and 24.1%, respectively, of our total volumes under these types of fee arrangements on a pro forma basis.

Fixed-fee arrangements. Under fixed-fee arrangements, we purchase natural gas from the producers at the wellhead at an index based price less a fixed fee to gather, dehydrate, compress, treat and/or process their natural gas. These types of arrangements typically require us to pay the producer for the value of the wellhead gas less the applicable fee. For the year ended December 31, 2004 and the nine months ended September 30, 2005, we purchased 35.3% and

30.5%, respectively, of our total volumes under these types of fee arrangements on a pro forma basis.

The following is a summary of our four largest natural gas purchase contracts based on volumes purchased for the year ended December 31, 2004. Under each of the contracts, we are required to purchase the supplied gas, subject to the demands of our resale purchasers and the operating conditions and capacity of our facilities. We do not guarantee the purchase of any particular quantity of the gas which is available for sale. The supplier delivers the gas to us at the inlet of our gathering systems and we obtain title to the gas at the delivery point. The gas delivered to us is required to meet specified quality requirements.

Continental Resources, Inc. We are a party to a fixed fee gas purchase contract with Continental Resources, Inc. dated as of August 1, 1999. For the year ended December 31, 2004 and the nine months ended September 30, 2005, gas purchased under the contract represented approximately 12.7% and 13.2%, respectively, on a pro forma basis, of our aggregate natural gas supply for that period. Under the contract, Continental Resources, Inc. has committed to supply us with all of the gas that it produces in a designated area in Blaine County, Oklahoma. The contract currently covers approximately 19 wells that are connected to our Matli gathering system. We pay Continental Resources the applicable index price for the raw natural gas delivered to us, less a transportation fee, a processing fee and a treating fee. The contract remains in effect for the life of the gas leases contained in the dedicated area. However, we have the right to terminate the contract by giving 30 days' notice.

Chesapeake Energy Corporation. We are a party to a percentage-of-proceeds gas purchase contract with Chesapeake Energy Corporation dated as of January 1, 2004. For the year ended December 31, 2004 and the nine months ended September 30, 2005, gas purchased under the contract represented approximately 8.0% and 5.4%, respectively, on a pro forma basis, of our aggregate natural gas supply for that period. Under the contract, Chesapeake Energy Corporation has committed to supply us with all of the gas it produces in a designated area primarily in Woods County, Oklahoma. The contract currently covers approximately 18 wells that are connected to our Eagle Chief gathering system. We pay Chesapeake Energy Corporation the following: (1) a fixed percentage of the applicable index price for the volumes of each NGL product derived at our Eagle Chief processing plant from the raw natural gas produced from the dedicated wells less a deduction for delivery, transportation and fractionation costs and (2) a fixed percentage of the applicable index price for the residue natural gas derived from the raw natural gas produced from the dedicated wells. The contract remains in effect for the life of the gas leases contained in the dedicated area. However, either party has the right to terminate the contract on January 1, 2009 or on any subsequent anniversary by giving 30 days' notice.

We are also a party to a percentage-of-index gas purchase contract with Chesapeake Energy Corporation dated July 20, 1983. For the year ended December 31, 2004 and the nine months ended September 30, 2005, gas purchased under the contract represented approximately 10.9% and 8.4%, respectively, on a pro forma basis, of our aggregate natural gas supply for that period. Under the contract, Chesapeake Energy Corporation has committed to supply us with all of the gas it produces in a designated area in Woods County, Oklahoma. The contract currently covers approximately 120 wells that are connected to our Eagle Chief gathering system. Under this contract, we pay Chesapeake Energy Corporation a price for the gas equal to a fixed percentage of the applicable index price. This contract remains in effect for the life of the gas leases contained in the dedicated area.

Range Resources Corporation. We are a party to a fixed-fee gas purchase contract with Range Resources Corporation dated as of November 1, 2002. For the year ended December 31, 2004 and the nine months ended September 30, 2005, gas purchased under the contract represented approximately 10.5% and 7.0%, respectively, on a pro forma basis, of our aggregate natural gas supply for that period. Under the contract, Range Resources Corporation has committed to supply us with all of the gas that it produces in a designated area in Blaine County, Oklahoma. The contract currently covers approximately 7 wells that are connected to our Matli gathering system. Under this contract, we pay Range Resources Corporation the applicable index price for the raw natural gas delivered to us less a fixed transportation fee. This contract remains in effect for the life of the lease. However, either party has the right to terminate the contract on November 1, 2007 or on any subsequent anniversary by giving 30 days' notice. In addition, we have the right to terminate the contract by giving 30 days' notice.

Compression Services Agreement

Under the compression services agreement that we entered into with Continental Resources, Inc. in connection with our initial public offering and effective as of January 28, 2005, Continental Resources, Inc. pays us a fixed monthly fee to provide compressed air and water at pressures sufficient to allow for the injection of either air or water into underground reservoirs for oil and gas secondary recovery operations. Under the compression services agreement, Continental Resources, Inc. is responsible for the provision to us of power and water to be utilized in the compression process. If our facilities do not meet the monthly volume requirements for compressed air and water, and the failure is not attributable to Continental Resources, Inc.'s failure to supply power or water or a force majeure, the fixed monthly payment will be reduced in proportion to the volumes of air or water we were unable to deliver during such month. Continental Resources, Inc. may terminate the compression services agreement if we are unable to deliver any compressed air and water for a period of more than 20 consecutive days and the failure is not attributable to Continental Resources, Inc.'s failure to supply power or water or a force majeure. The agreement has an initial term of four years and will thereafter automatically renew for additional one month terms unless terminated by either party by giving notice at least 15 days prior to the end of the then current term.

Our Growth Strategy

Our growth strategy contemplates engaging in construction and expansion opportunities as well as complementary acquisitions of midstream assets in our operating areas. We intend to pursue construction and expansion projects to meet new or increased demand for our midstream services. In addition, we intend to pursue acquisitions that we believe will allow us to capitalize on our existing infrastructure, personnel and producer and customer relationships to provide an integrated package of services. We may also pursue selected acquisitions in new geographic areas to the extent they present growth opportunities similar to those we are pursuing in our existing areas of operations. To successfully execute our growth strategy, we will require access to capital on competitive terms. We intend to finance future acquisitions primarily by using the capacity available under our bank credit facility and equity or debt offerings or a combination of both.

Capital Expenditures. We make capital expenditures either to maintain our assets or the supply to our assets or for expansion projects to increase our total segment margin. Maintenance capital is capital employed to replace partially or fully depreciated assets to maintain the existing operating capacity of our assets and to extend their useful lives, or other capital expenditures that are incurred in maintaining existing system volumes and related cash flows. Expansion capital expenditures represent capital expenditures made to expand or increase the efficiency of the existing operating capacity of our assets. Expansion capital expenditures include expenditures that facilitate an increase in volumes within our operations, whether through construction or acquisition. Expenditures that reduce our operating costs will be considered expansion capital expenditures only if the reduction in operating expenses exceeds cost reductions typically resulting from routine maintenance. Our decisions whether to spend capital on expansion projects are generally based on the target rate of return, as well as the cash flow capabilities of the assets.

Acquisitions. In analyzing a particular acquisition, we consider the operational, financial and strategic benefits of the transaction. Our analysis includes location of the assets, strategic fit of the asset in relation to our business strategy, expertise required to manage the asset, capital required to integrate and maintain the asset, and the competitive environment of the area where the assets are located. From a financial perspective, we analyze the rate of return the assets will generate under various case scenarios, comparative market parameters and cash flow capabilities of the assets.

Items Impacting Comparability of Our Financial Results

Our historical results of operations for the periods presented may not be comparable, either from period to period or going forward, for the reasons described below.

Our Formation

We were formed in October 2004 to own and operate the assets that have historically been owned and operated by Continental Gas, Inc. and Hiland Partners, LLC. As part of our formation, immediately prior to consummation of our initial public offering, the former owners of Continental Gas, Inc. and Hiland Partners, LLC contributed to us all of the assets and operations of Continental Gas, Inc. other than a portion of its working capital assets and all of the assets and operations of Hiland Partners, LLC, other than a portion of its working capital assets and the assets related to the Bakken gathering system. Effective September 1, 2005, we acquired Hiland Partners, LLC, which owns the Bakken gathering system.

Continental Gas, Inc. is our predecessor for accounting purposes and has historically owned all of our natural gas gathering, processing and fractionation assets other than the Worland and Bakken gathering systems. As a result, our historical financial statements for the periods prior to February 15, 2005 are the financial statements of Continental Gas, Inc.

Hiland Partners, LLC has historically owned our Worland gathering system, our Horse Creek compression facility, our Cedar Hills water injection plant located next to our Cedar Hills compression facility and the Bakken gathering system. For a discussion of the results of operations of the net assets and operations acquired from Hiland Partners, LLC, please read " Results of Operations of Net Assets and Operations Acquired from Hiland Partners, LLC." The financial statements of the net assets and operations acquired from Hiland Partners, LLC, together with the notes thereto, are included in this prospectus.

Restructuring of Compression Facilities Lease

Prior to our initial public offering, Hiland Partners, LLC owned our Horse Creek air compression facility and our Cedar Hills water injection facility. In 2002, Hiland Partners, LLC entered into a five year lease agreement with Continental Resources, Inc., pursuant to which Hiland Partners, LLC leased the facilities to Continental Resources, Inc. Continental Resources, Inc. used its own personnel to operate the facilities, and Hiland Partners, LLC made no operational decisions. In connection with our formation and our initial public offering, we entered into a four-year services agreement with Continental Resources, Inc., effective as of January 28, 2005, that replaced the existing lease. Under the services agreement, we own and operate the facilities and provide air compression and water injection services to Continental Resources, Inc. for a fee. As part of the restructuring, the personnel at Continental Resources, Inc. that operated the facilities were transferred to us. Under the new services agreement, we receive a fixed payment of approximately $4.8 million per year as compared to $3.8 million per year under the prior lease agreement. In connection with the new services arrangement, we incur approximately $1.0 million per year in additional operating costs. For a description of the restructured agreement, please read " Our Contracts Compression Services Agreement."

Construction and Acquisition Activities

Since our inception, we have grown through a combination of building gas gathering and processing assets and acquisitions. For example, we commenced operation of the Matli gathering system in 1999 and constructed the Matli processing plant in 2003. Additionally, we acquired the Worland gathering system in 2000 and the Carmen gathering system in 2003. We acquired the Carmen gathering system in 2003 as an expansion of our Eagle Chief gathering system. Prior to our acquisition of the Carmen gathering system, we purchased the gas from the previous owner, processed it and returned it to the previous owner pursuant to a keep-whole arrangement. After we acquired the Carmen gathering system, we terminated this keep-whole arrangement and now sell the gas at the tailgate of the Eagle Chief processing plant. In addition, we completed the Bakken acquisition in September 2005. Our historical acquisitions were completed at different dates and with numerous sellers and were accounted for using the purchase method of accounting. Under the purchase method of accounting, results from such acquisitions are recorded in the financial statements only from the date of acquisition.

Our Results of Operations

Set forth in the table below is our financial and operating data for the periods indicated. Operations from our Worland gathering system and compression assets contributed to us by Hiland Partners, LLC are reflected only from February 15, 2005, the date of our initial public offering. Other than pro forma information, the historical information set forth in the table and related discussion below does not include operations from our Bakken gathering system for periods prior to September 1, 2005, the effective date of the Bakken acquisition.

	Predecessor			Nine Months Ended September 30,			
	Year Ended December 31,			2004	2005		
	2002	**2003(1)**	**2004**	**Predecessor**	**Predecessor(2)**	**Hiland Partners, LP(3)**	**Total**
	(audited)			(unaudited)			
	(in thousands)						
Total Segment Margin Data:							
Midstream revenues	$ 35,228	$ 76,018	$ 98,296	$ 70,286	$ 11,813	$ 83,481	$ 95,294
Midstream purchases	27,935	67,002	82,532	59,846	9,747	67,801	77,548
Midstream segment margin	7,293	9,016	15,764	10,440	2,066	15,680	17,746
Compression revenues (4)						3,012	3,012
Total segment margin (5)	$ 7,293	$ 9,016	$ 15,764	$ 10,440	$ 2,066	$ 18,692	$ 20,758
Summary of Operations Data:							
Midstream revenues	$ 35,228	$ 76,018	$ 98,296	$ 70,286	$ 11,813	$ 83,481	$ 95,294
Compression revenues						3,012	3,012
Total revenues	35,228	76,018	98,296	70,286	11,813	86,493	98,306
Operating costs and expenses:							
Midstream purchases (exclusive of items shown separately below)	27,935	67,002	82,532	59,846	9,747	67,801	77,548
Operations and maintenance	3,509	3,714	4,933	3,624	780	4,303	5,083
Property impairment		1,535					
Depreciation, amortization and accretion	2,370	3,304	4,127	3,003	512	6,412	6,924
(Gain) loss on asset sales	(12)	34	(19)	(15)			
Bad debt	295						
General and administrative	730	770	1,082	680	166	1,373	1,539
Total operating costs and expenses	34,827	76,359	92,655	67,138	11,205	79,889	91,094

				Nine Months Ended September 30,			
Operating income (loss)	401	(341)	5,641	3,148	608	6,604	7,212
Other income (expense)	(113)	(487)	(764)	(561)	(115)	(899)	(1,014)
Income (loss) from continuing operations	288	(828)	4,877	2,587	493	5,705	6,198
Discontinued operations, net	199	246	35	34			
Income (loss) before change in accounting principle	487	(582)	4,912	2,621	493	5,705	6,198
Cumulative effect of change in accounting principle		1,554					
Net income	$ 487	$ 972	$ 4,912	$ 2,621	$ 493	$ 5,705	$ 6,198
Operating Data:							
Natural gas sales (MMBtu/d)	26,599	37,701	40,560	40,730	37,052	44,226	43,044
NGL sales (Bbls/d)	950	895	1,133	1,095	1,206	1,631	1,561

(1) Includes operations of our Carmen gathering system beginning August 1, 2003, the date we acquired these assets.

(2) Amounts presented in the Predecessor column include only the operations of Continental Gas, Inc. for the period prior to the initial public offering of Hiland Partners, LP on February 15, 2005.

(3) Amounts presented in the Hiland Partners, LP column include only the activity for the period beginning on the initial public offering date of February 15, 2005. These amounts include the operations of the assets contributed from Hiland Partners, LLC at the closing of our initial public offering (Worland gathering system and compression assets).

(4) Compression revenues and compression segment margin are the same. There are no compression purchases associated with the compression segment.

(5) Reconciliation of total segment margin to operating income:

	Year Ended December 31,			Nine Months Ended September 30,			
	Predecessor			2004	2005		
	2002	2003	2004	Predecessor	Predecessor	Hiland Partners, LP	Total
	(audited)			(unaudited)			
	(in thousands)						
Operating income	$ 401	$ (341)	$ 5,641	$ 3,148	$ 608	$ 6,604	$ 7,212
Add:							
Operations and maintenance	3,509	3,714	4,933	3,624	780	4,303	5,083
Property impairment		1,535					
Depreciation, amortization and accretion	2,370	3,304	4,127	3,003	512	6,412	6,924
(Gain) loss on asset sales	(12)	34	(19)	(15)			
Bad debt	295						
General and administrative	730	770	1,082	680	166	1,373	1,539
Total segment margin	$ 7,293	$ 9,016	$ 15,764	$ 10,440	$ 2,066	$ 18,692	$ 20,758

Nine Months Ended September 30, 2005 Compared with Nine Months Ended September 30, 2004

Revenues. Our total revenues (midstream and compression) were $98.3 million for the nine months ended September 30, 2005 compared to $70.3 million for the nine months ended September 30, 2004, an increase of $28.0 million, or 39.9%. This increase was primarily attributable to (1) higher average realized natural gas prices and NGL sales prices, (2) increased volumes attributable to the contribution of the Worland gathering system by Hiland Partners, LLC on February 15, 2005 to us, (3) increased revenues from compression assets contributed by Hiland Partners, LLC on February 15, 2005 to us and (4) increased volumes attributable to the acquisition of the Bakken gathering system effective September 1, 2005.

Our midstream revenues were $95.3 million for the nine months ended September 30, 2005 compared to $70.3 million for the nine months ended September 30, 2004, an increase of $25.0 million, or 35.6%. Of this increase, $19.8 million was attributable to higher average realized natural gas prices and NGL sales prices and $5.2 million was attributable to higher residue natural gas and NGL sales volumes. The volume increase is primarily attributable to the contribution of the Worland gathering system from Hiland Partners, LLC on February 15, 2005 and the acquisition of the Bakken gathering system effective September 1, 2005.

Our natural gas sales volumes were 43,044 MMBtu/d for the nine months ended September 30, 2005 compared to 40,730 MMBtu/d for the nine months ended September 30, 2004, an increase of 2,314 MMBtu/d, or 5.7%. Our NGL sales volumes were 1,561 Bbls/d for the nine months ended September 30, 2005 compared to 1,095 Bbls/d for the nine months ended September 30, 2004, an increase of 466 Bbls/d, or 42.6%. These increases in volumes are primarily associated with the contribution of the Worland gathering system from Hiland Partners, LLC on February 15, 2005 and the acquisition of the Bakken gathering system from Hiland Partners, LLC effective September 1, 2005.

Our average realized natural gas sales prices were $6.35 per MMBtu for the nine months ended September 30, 2005 compared to $5.24 per MMBtu for the nine months ended September 30, 2004, an increase of $1.11 per MMBtu, or 21.2%. In addition, average realized NGL sales prices were $0.96 per gallon for the nine months ended September 30, 2005 compared to $0.71 per gallon for the nine months ended September 30, 2004, an increase of $0.25 per gallon or 35.2%. The change in our average realized natural gas and NGL sales prices was primarily a result of higher index prices due to a tightening of supply and demand fundamentals for energy, which caused crude oil and natural gas prices to rise during the nine months ended September 30, 2005 compared to the nine months ended September 30, 2004.

Our compression revenues were $3.0 million for the nine months ended September 30, 2005. The compression assets were contributed by Hiland Partners, LLC on February 15, 2005. Continental Gas, Inc., our predecessor, did not have a compression segment, therefore, there were no compression revenues reported for the nine months ended September 30, 2004.

Midstream Purchases. Our midstream purchases were $77.5 million for the nine months ended September 30, 2005 compared to $59.8 million for the nine months ended September 30, 2004, an increase of $17.7 million, or 29.6%. This increase is primarily attributable to higher average realized natural gas prices and NGL sales prices, the contribution of the Worland gathering system from Hiland Partners, LLC on February 15, 2005 and the acquisition of the Bakken gathering system effective September 1, 2005.

Operations and Maintenance. Our operations and maintenance expense totaled $5.1 million for the nine months ended September 30, 2005 compared with $3.6 million for the nine months ended September 30, 2004, an increase of $1.5 million, or 40.3%. This increase is primarily attributable to the contribution of the Worland gathering system and the compression assets from Hiland Partners, LLC on February 15, 2005 and the acquisition of the Bakken gathering system from Hiland Partners, LLC effective September 1, 2005.

Depreciation, Amortization and Accretion. Our depreciation, amortization and accretion expense totaled $6.9 million for the nine months ended September 30, 2005 compared with $3.0 million for the nine months ended September 30, 2004, an increase of $3.9 million, or 130.6%. This increase is primarily attributable to the contribution of the Worland gathering system and the compression assets from Hiland Partners, LLC on February 15, 2005 and the acquisition of the Bakken gathering system effective September 1, 2005.

General and Administrative. Our general and administrative expense totaled $1.5 million for the nine months ended September 30, 2005 compared with $0.7 million for the nine months ended September 30, 2004, an increase of $0.8 million, or 126.3%. The increase is primarily attributable to adding staff as a result of our growth and the additional costs of being a public company.

Other Income (Expense). Our other income (expense) totaled ($1.0) million for the nine months ended September 30, 2005 compared with ($0.6) million for the nine months ended September 30, 2004, a increase in expense of $0.4 million, or 80.7%. The increase is primarily attributable to additional interest expense and amortization of deferred debt issuance costs associated with our credit facility relating to the acquisition of the Bakken gathering system effective September 1, 2005.

Year Ended December 31, 2004 Compared with Year Ended December 31, 2003

Revenues. Midstream revenues were $98.3 million for the year ended December 31, 2004 compared to $76.0 million for the year ended December 31, 2003, an increase of $22.3 million, or 29.3%. Of this increase, $12.7 million was attributable to higher average realized natural gas sales prices and NGL sales prices and $7.2 million was attributable to higher residue and NGL sales volumes.

Natural gas sales volumes were 40,560 MMBtu/d for the year ended December 31, 2004 compared to 37,701 MMBtu/d for the year ended December 31, 2003, an increase of 2,859 MMBtu/d, or 7.6%. NGL sales volumes were 1,133 Bbls/d for the year ended December 31, 2004 compared to 895 Bbls/d for the year ended December 31, 2003, an increase of 238 Bbls/d, or 26.6%. Natural gas and NGL sales volumes increased primarily as a result of our acquisition of the Carmen gathering system from Great Plains Pipeline Company in August 2003.

Average realized natural gas sales prices were $5.49 per MMBtu for the year ended December 31, 2004 compared to $4.84 per MMBtu for the year ended December 31, 2003, an increase of $0.65 per MMBtu, or 13.4%. In addition, average realized NGL sales prices were $0.76 per gallon for the year ended December 31, 2004 compared to $0.58 per gallon for the year ended December 31, 2003, an increase of $0.18 per gallon, or 31.0%. The change in our average realized natural gas and NGL sales prices was primarily a result of higher index prices. The change in index prices was primarily a result of a tightening of supply and demand fundamentals for energy which caused crude oil and natural gas prices to rise significantly during the year ended December 31, 2004 compared to the year ended December 31, 2003.

Midstream Purchases. Midstream purchases were $82.5 million for the year ended December 31, 2004 compared to $67.0 million for the year ended December 31, 2003, an increase of $15.5 million, or 23.2%. This increase was directly attributable to an increase in natural gas and NGL sales volumes as a result of our acquisition of the Carmen gathering system from Great Plains Pipeline Company in August 2003 and an increase in natural gas and NGL prices.

Operations and Maintenance. Operations and maintenance expenses totaled $4.9 million for the year ended December 31, 2004 compared with $3.7 million for the year ended December 31, 2003, an increase of $1.2 million, or 32.8%. The increase was primarily attributable to our acquisition of the Carmen gathering system.

Property Impairment. In 2003, we recognized a $1.5 million impairment expense as a result of volume declines at gathering facilities located in Texas, Mississippi and Wyoming. There was no impairment expense recorded in 2004.

Depreciation, Amortization and Accretion. Depreciation, amortization and accretion expenses totaled $4.1 million for the year ended December 31, 2004 compared with $3.3 million for the year ended December 31, 2003, an increase of $0.8 million, or 24.9%. The increase was primarily due to our acquisition of the Carmen gathering system in August 2003 and expansion of the Matli gathering system in 2003.

General and Administrative. General and administrative expenses totaled $1.1 million for the year ended December 31, 2004 compared with $0.8 million for the year ended December 31, 2003, an increase of $0.3 million, or 40.5%. The increase is associated with an increase in employees caused by our growth and preparation for our initial public offering.

Other Income (Expense). Other income (expense) totaled ($0.8) million for the year ended December 31, 2004 compared with ($0.5) million for the year ended December 31, 2003, an increase of $0.3 million, or 56.9%. This increase relates to the acquisition of the Carmen gathering system in August 2003 and expansion of the Matli Gathering System. We acquired the Carmen gathering system for a net purchase price of $12.0 million that was financed with bank debt.

Cumulative Effect of Change in Accounting Principle. Cumulative effect of change in accounting principle totaled $1.6 million for the year ended December 31, 2003. In 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations (SFAS No. 143). SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset.

Subsequently, the asset retirement cost is allocated to expense using a systematic and rational method and the liability is accreted to its face amount.

We adopted SFAS No. 143 on January 1, 2003. The impact of adopting SFAS No. 143 has been accounted for through a cumulative effect adjustment that amounted to $1.6 million increase to net income recorded on January 1, 2003.

Year Ended December 31, 2003 Compared with Year Ended December 31, 2002

Revenues. Midstream revenues were $76.0 million for the year ended December 31, 2003 compared to $35.2 million for the year ended December 31, 2002, an increase of $40.8 million, or 115.8%. Of this increase, $27.8 million is attributable to higher average realized natural gas sales prices and averaged realized NGL sales prices and $11.8 million is attributable to an increase in residue sales volumes offset partially by a decrease in NGL sales volumes.

Natural gas sales volumes were 37,701 MMBtu/d for the year ended December 31, 2003 compared to 26,599 MMBtu/d for the year ended December 31, 2002, an increase of 11,102 MMBtu/d, or 41.7%. NGL sales volumes were 895 Bbls/d for the year ended December 31, 2003 compared to 950 Bbls/d for the year ended December 31, 2002, a decrease of 55 Bbls/d, or 5.8%. Natural gas sales volumes increased primarily as a result of our acquisition of the Carmen gathering system.

Average realized natural gas sales prices were $4.84 per MMBtu for the year ended December 31, 2003 compared to $2.99 per MMBtu for the year ended December 31, 2002, an increase of $1.85 per MMBtu, or 61.9%. In addition, average realized NGL sales prices were $0.58 per gallon for the year ended December 31, 2003 compared to $0.41 per gallon for the year ended December 31, 2002, an increase of $0.17 per gallon, or 41.5%. The change in our average realized natural gas and NGL sales prices was primarily a result of higher index prices. The change in index prices was primarily a result of a tightening of supply and demand fundamentals for energy which caused crude oil and natural gas prices to rise significantly during the year ended December 31, 2003 compared to the year ended December 31, 2002.

Midstream Purchases. Midstream purchases were $67.0 million for the year ended December 31, 2003 compared to $27.9 million for the year ended December 31, 2002, an increase of $39.1 million, or 139.8%. This increase was directly attributable to an increase in natural gas and NGL sales volumes as a result of our acquisition of the Carmen gathering system and an increase in natural gas and NGL prices.

Property Impairment. In 2003, we recognized a $1.5 million impairment expense as a result of volume declines at gathering facilities located in Texas, Mississippi and Wyoming. There was no impairment expense recorded in 2002.

Depreciation, Amortization and Accretion. Depreciation, amortization and accretion expenses totaled $3.3 million for the year ended December 31, 2003 compared with $2.4 million for the year ended December 31, 2002, an increase of $0.9 million, or 39.4%. The increase was primarily due to our acquisition of the Carmen gathering system in August 2003 and expansion of the Matli gathering system.

Other Income (Expense). Other income (expense) totaled ($0.49) million for the year ended December 31, 2003 compared with ($0.1) million for the year ended December 31, 2002, an increase of $0.4 million, or 331.0%. This increase relates to the acquisition of the Carmen gathering system in August 2003 and expansion of the Matli gathering system.

Cumulative Effect of Change in Accounting Principle. Cumulative effect of change in accounting principle totaled $1.6 million for the year ended December 31, 2003. This cumulative effect of change in accounting principle was the result of our January 1, 2003 adoption of SFAS No. 143.

Results of Operations of Net Assets and Operations Acquired from Hiland Partners, LLC

The following table and the discussion that follows provide a comparison of the results of the operating activities of the net assets acquired from Hiland Partners, LLC for the years ended December 31, 2002, 2003 and 2004. Hiland Partners, LLC owned our Worland gathering system, our Horse Creek compression facility and our Cedar Hills water injection plant located next to our Cedar Hills compression facility prior to the contribution of those assets to us in connection with our initial public offering on February 15, 2005. Hiland Partners, LLC's principal remaining asset after our initial public offering was the Bakken gathering system, which commenced operations November 8, 2004. We acquired the remaining net assets of Hiland Partners, LLC effective as of September 1, 2005.

	Net Assets Acquired From Hiland Partners, LLC		
	Year Ended December 31,		
	2002	2003	2004
	(audited)		
	(in thousands)		
Total Segment Margin Data:			
Midstream revenues	$ 5,480	$ 7,262	$ 10,481
Midstream purchases	1,439	2,826	4,600
Midstream segment margin	4,041	4,436	5,881
Compression revenues(1)	244	3,300	3,854
Total segment margin(2)	$ 4,285	$ 7,736	$ 9,735
Summary of Operations Data:			
Midstream revenues	$ 5,480	$ 7,262	$ 10,481
Compression revenues	244	3,300	3,854
Total revenues	5,724	10,562	14,335
Operating costs and expenses:			
Midstream purchases (exclusive of items shown separately below)	1,439	2,826	4,600
Operations and maintenance	1,779	1,900	2,080
Depreciation amortization and accretion	522	1,684	2,311
Loss on asset sales	36		
General and administrative	156	101	97
Total operating costs and expenses	3,932	6,511	9,088
Operating income	1,792	4,051	5,247
Interest and other financing costs, net	278	563	766
Income before change in accounting principle	1,514	3,488	4,481
Cumulative effect of change in accounting principle		(73)	
Net income	$ 1,514	$ 3,415	$ 4,481
Operating Data (unaudited):			
Natural gas sales (MMBtu/d)	4,549	3,756	3,503
NGL sales (Bbls/d)	282	282	304

(1) Compression revenues and compression segment margin are the same. There are no compression purchases associated with the compression segment.

(2)

Reconciliation of total segment margin to operating income:

	Net Assets Acquired From Hiland Partners, LLC		
	Year Ended December 31,		
	2002	2003	2004
	(audited)		
	(in thousands)		
Operating income	$ 1,792	$ 4,051	$ 5,247
Add:			
Operations and maintenance	1,779	1,900	2,080
Depreciation, amortization and accretion	522	1,684	2,311
(Gain) loss on asset sales	36		
General and administrative	156	101	97
Total segment margin	$ 4,285	$ 7,736	$ 9,735

Year Ended December 31, 2004 Compared with Year Ended December 31, 2003

Revenues. Total revenues (midstream and compression) were $14.3 million for the year ended December 31, 2004 compared to $10.6 million for the year ended December 31, 2003, an increase of $3.8 million, or 35.7%.

Midstream revenues were $10.5 million for the year ended December 31, 2004 compared to $7.3 million for the year ended December 31, 2003, an increase of $3.2 million, or 44.3%. Of this increase, $2.9 million was attributable to higher average realized natural gas sales prices and average realized NGL sales prices. This increase was offset by a $0.1 million decrease due to lower residue sales volumes.

Natural gas sales volumes were 3,503 MMBtu/d for the year ended December 31, 2004 compared to 3,756 MMBtu/d for the year ended December 31, 2003, a decrease of 253 MMBtu/d, or 6.7%. NGL sales volumes were 304 Bbls/d for the year ended December 31, 2004 compared to 282 Bbls/d for the year ended December 31, 2003, an increase of 22 Bbls/d, or 7.8%. Natural gas sales volumes decreased primarily due to the shutdown and maintenance of a high-pressure gas trunk line serving the plant. This line was shut down for a forty-five day period in the first six months of 2004. This decrease was partially offset by volumes associated with the start-up of the Bakken plant. The increase in NGL sales volumes was primarily attributable to NGL extraction volumes associated with the start-up of the Bakken plant.

Average realized natural gas sales prices were $5.32 per MMBtu for the year ended December 31, 2004 compared to $3.39 per MMBtu for the year ended December 31, 2003, an increase of $1.93 per MMBtu, or 56.9%. In addition, average realized NGL sales prices were $0.70 per gallon for the year ended December 31, 2004 compared to $0.60 per gallon for the year ended December 31, 2003, an increase of $0.10 per gallon, or 16.7%. The change in our average realized natural gas and NGL sales prices was primarily a result of higher index prices. The change in index prices was primarily a result of a tightening of supply and demand fundamentals for energy which caused crude oil and natural gas prices to rise significantly during the year ended December 31, 2004 compared to the year ended December 31, 2003.

Compression revenues were $3.9 million for the year ended December 31, 2004 compared to $3.3 million for the year ended December 31, 2003, an increase of $0.6 million, or 16.8%. This increase was directly attributable to the expansion of our compression facilities with a corresponding increase in the monthly lease payment.

Midstream Purchases. Midstream purchases were $4.6 million for the year ended December 31, 2004 compared to $2.8 million for the year ended December 31, 2003, an increase of $1.8 million, or 62.8%. This increase was primarily attributable to purchases associated with the start-up of the Bakken plant and the increase of natural gas and NGL prices.

Depreciation, Amortization and Accretion. Depreciation, amortization and accretion expenses totaled $2.3 million for the year ended December 31, 2004 compared with $1.7 million for the year ended December 31, 2003, an increase of $0.6 million, or 37.2%. The increase was attributable to acquiring additional compression equipment in the second half of 2003 that we leased to Continental Resources and depreciation associated with the Bakken gathering system that became operational on November 8, 2004.

Interest and Other Financing Costs, Net. Interest and other financing costs totaled $0.8 million for the year ended December 31, 2004 compared with $0.6 million for the year ended December 31, 2003, an increase of $0.2 million, or 36.1%. The increase is attributable to financing compression equipment purchased during 2003 and financing the Bakken gathering system which became operational on November 8, 2004.

Cumulative Effect of Change in Accounting Principle. Cumulative effect of change in accounting principle totaled $0.1 million for the year ended December 31, 2003. This cumulative effect of change in accounting principle was the result of our January 1, 2003 adoption of SFAS No. 143.

Year Ended December 31, 2003 Compared with Year Ended December 31, 2002

Revenues. Total revenues (midstream and compression) were $10.6 million for the year ended December 31, 2003 compared to $5.7 million for the year ended December 31, 2002, an increase of $4.8 million, or 84.5%.

Midstream revenues were $7.3 million for the year ended December 31, 2003 compared to $5.5 million for the year ended December 31, 2002, an increase of $1.8 million, or 32.5%. Of this increase, $2.6 million was attributable to higher average realized natural gas sales prices and average realized NGL sales prices. This increase was offset by a $0.5 million decrease attributable to lower residue and NGL sales volumes.

Natural gas sales volumes were 3,756 MMBtu/d for the year ended December 31, 2003 compared to 4,549 MMBtu/d for the year ended December 31, 2002, a decrease of 793 MMBtu/d, or 17.4%. The decrease was primarily attributable to the sale of our Dobie Creek pipeline system. NGL sales volumes were relatively stable at 282 Bbls/d for the year ended December 31, 2003 compared to 282 Bbls/d for the year ended December 31, 2002.

Average realized natural gas sales prices were $3.40 per MMBtu for the year ended December 31, 2003 compared to $1.92 per MMBtu for the year ended December 31, 2002, an increase of $1.48 per MMBtu, or 77.1%. In addition, average realized NGL sales prices were $0.60 per gallon for the year ended December 31, 2003 compared to $0.46 per gallon for the year ended December 31, 2002, an increase of $0.14 per gallon or 30.4%. The change in our average realized natural gas and NGL sales prices was primarily a result of higher index prices. The change in index prices was primarily a result of a tightening of supply and demand fundamentals for energy which caused crude oil and natural gas prices to rise significantly during the year ended December 31, 2003 compared to the year ended December 31, 2002.

Compression revenues were $3.3 million for the year ended December 31, 2003 compared to $0.2 million for the year ended December 31, 2002, an increase of $3.1 million. This increase was directly attributable to the expansion of our compression facilities with a corresponding increase in the monthly lease payment.

Midstream Purchases. Midstream purchases were $2.8 million for the year ended December 31, 2003 compared to $1.4 million for the year ended December 31, 2002, an increase of $1.4 million, or 96.4%. This increase was attributable to the increase of natural gas and NGL prices, partially offset by a decrease in volumes.

Depreciation, Amortization and Accretion. Depreciation, amortization and accretion expenses totaled $1.7 million for the year ended December 31, 2003 compared with $0.5 million for the year ended December 31, 2002, an increase of $1.2 million, or 222.6%. The increase was attributable to adding compression equipment in December 2002 that we lease to Continental Resources.

Interest and Other Financing Costs, Net. Interest and other financing costs totaled $0.6 million for the year ended December 31, 2003 compared with $0.3 million for the year ended December 31, 2002, an increase of $0.3 million, or 102.5%. In December 2002 and in 2003, we purchased compressors that we leased to Continental Resources to be used in their secondary production recovery project. These equipment purchases were made with bank financing.

Cumulative Effect of Change in Accounting Principle. Cumulative effect of change in accounting principle totaled $0.1 million for year ended December 31, 2003. This cumulative effect of change in accounting principle was the result of our January 1, 2003 adoption of SFAS No. 143.

General Trends and Outlook

We expect our business to continue to be affected by the following key trends. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about or interpretations of available information prove to be incorrect, our expectations may vary materially from actual results. Please see "Forward Looking Statements."

U.S. Gas Supply and Outlook. We believe that current natural gas prices will continue to result in relatively high levels of natural gas-related drilling as producers seek to increase their level of natural gas production. Although the number of U.S. natural gas wells drilled has increased overall in recent years, a corresponding increase in production has not been realized, primarily as a result of smaller discoveries. We believe that an increase in U.S. drilling activity and additional sources of supply such as liquefied natural gas, or LNG, imports will be required for the natural gas industry to meet the expected increased demand for, and to compensate for the slowing production of, natural gas in the United States.

A number of the areas in which we operate are experiencing significant drilling activity as result of recent high natural gas prices, new discoveries and the implementation of new exploration and production techniques. We believe that this higher level of activity will continue. We also believe that our Badlands gathering system is located in an area where ongoing secondary recovery operations may provide us with additional natural gas volumes.

While we anticipate continued high levels of exploration and production activities in a number of the areas in which we operate, fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. Drilling activity generally decreases as oil and natural gas prices decrease. We have no control over the level of drilling activity in the areas of our operations.

Processing Margins. During 2003, 2004 and the first nine months of 2005, we generally have seen our margins increase as natural gas prices and NGL prices have increased, primarily as a result of our percentage-of-proceeds contracts. During 2003 and 2004, this positive impact on our margins had been partially offset by the negative impact on our margins resulting from the price of natural gas increasing relative to the price of NGLs, primarily as a result of our percentage-of-index contracts. Our profitability is dependent upon pricing and market demand for natural gas and NGLs, which are beyond our control and have been volatile.

Rising Interest Rate Environment. 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. Interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. Although this could limit our ability to raise funds in the debt capital markets, we expect to remain competitive with respect to acquisitions and capital projects, as our competitors would face similar circumstances. As with other yield oriented securities, our unit price is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank related yield oriented securities for investment decision making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue additional equity to make acquisitions, reduce debt or for other purposes.

Impact of Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the periods presented.

Liquidity and Capital Resources

Overview

Cash generated from operations, borrowings under our credit facility and funds from private and future public equity and debt offerings are our primary sources of liquidity. We believe that funds from these sources should be sufficient to meet both our short-term working capital requirements and our long-term capital expenditure requirements. Our ability to pay distributions to our unitholders, to fund planned capital expenditures and to make acquisitions depends upon our future operating performance, and more broadly, on the availability of equity and debt financing, which will be affected by prevailing economic conditions in our industry and financial, business and other factors, some of which are beyond our control.

Cash Flows

Nine Months Ended September 30, 2005 Compared to Nine Months Ended September 30, 2004

Cash Flows from Operating Activities. Our cash flows from operating activities decreased by $6.0 million to $0.9 million for the nine months ended September 30, 2005 from $6.9 million for the nine months ended September 30, 2004. Working capital items, exclusive of cash, decreased cash flows by $13.7 million to $(12.6) million during the first nine months ended September 30, 2005 from $1.1 million for the nine months ended September 30, 2004, primarily as a result of replenishing our accounts receivable after the closing of the initial public offering, increased accounts receivable as a result of higher realized prices for natural gas and NGLs and additional accounts receivable generated from midstream sales from the Bakken gathering system. In connection with our formation, the $9.1 million of accounts receivables of Continental Gas, Inc. was retained by the former owners of Continental Gas, Inc. Net income for the nine months ended September 30, 2005 was $6.2 million, an increase of $3.6 million from a net income of $2.6 million for the nine months ended September 30, 2004. Our non-cash expenses increased $4.2 million in the first nine months of 2005 compared with the same period in 2004.

Cash Flows Used for Investing Activities. Our cash flows used for investing activities, which represent investments in property and equipment, increased by $60.3 million to $65.2 million for the nine months ended September 30, 2005 from $4.9 million for the nine months ended September 30, 2004. Our acquisition of the Bakken gathering system assets totaled approximately $62.4 million.

Cash Flows from Financing Activities. Our cash flows from financing activities increased to $70.9 million for the nine months ended September 30, 2005 from $(2.3) million for the nine months ended September 30, 2004. We completed our initial public offering of 2,300,000 common units on February 15, 2005, receiving net proceeds of $48.1 million. The proceeds from the public offering were used to (1) pay remaining offering costs of $2.2 million and deferred debt issuance costs of $0.6 million, (2) pay outstanding indebtedness of $22.9 million, (3) redeem $6.3 million of common units from an affiliate of Harold Hamm and the Hamm Trusts, and (4) make a $3.9 million distribution to the previous owners of Hiland Partners, LLC. We retained $12.2 million to replenish working capital. During the period from January 1, 2005 to February 14, 2005, Continental Gas, Inc. repaid $1.1 million of its outstanding indebtedness. On September 26, 2005, we borrowed $93.7 million under our amended credit facility in connection with our acquisition of Hiland Partners, LLC and incurred an additional $0.3 million in debt issuance costs by amending our credit facility. In addition, our cash flows from financing activities for the nine months ended September 30, 2005 reflect a $27.8 million distribution, for accounting purposes, to the controlling member of our general partner in connection with the acquisition of Hiland Partners, LLC. The controlling member of our general partner owned 49% of Hiland Partners, LLC. The $27.8 million distribution presented in our statement of cash flows reflects the difference in the purchase price paid to the controlling member of our general partner and his cost basis in the net assets of Hiland Partners, LLC. During the third quarter our general partner contributed $6,000 to maintain its 2% interest in the Partnership as a result of our issuance of 8,000 restricted common units to non-employee board members of our general partner. From February 15, 2005 through September 30, 2005, we distributed $4.8 million to our unitholders.

Twelve Months Ended December 31, 2004 Compared to Twelve Months Ended December 31, 2003 and Twelve Months Ended December 31, 2003 Compared to Twelve Months Ended December 31, 2002

Cash flows from operating activities. Net cash provided by operating activities was $8.0 million and $4.5 million for 2004 and 2003, respectively, an increase of $3.5 million. Net cash provided by operating activities increased during 2004 principally due to higher total segment margin of $6.7 million. The increase in total segment margin was attributable to an increase in natural gas and NGL prices as well as an increase in natural gas and NGL sales volumes as a result of our acquisition of the Carmen gathering system in August 2003 and expansion of our Matli gathering system throughout 2003. However, this increase was partially offset by higher operating expenses of $1.2 million and changes in working capital items using $1.2 million in 2004 as compared to providing $0.1 million in 2003.

Net cash provided by operating activities was $4.5 million and $4.8 million for the year ended December 31, 2003 and 2002, respectively, a decrease of $0.3 million. Total segment margin increased $1.7 million for the year ended December 31, 2003 as compared to the year ended December 31, 2002. The increase in total segment margin was attributable to an increase of natural gas and NGL prices as well as an increase in natural gas sales volumes. However this increase was offset by changes in working capital items that impacted cash provided by operating activities. Changes in these working capital items provided $2.1 million in 2002 as compared to $0.1 million in 2003.

Cash flows used in investing activities. Net cash used in investing activities was $5.3 million for 2004 and $17.3 million for 2003. The year ended December 31, 2003 includes $12.0 million of capital expenditures for our acquisition of the Carmen gathering system. Net cash used in investing activities was $17.3 million and $5.6 million for the years ended December 31, 2003 and 2002, respectively. Capital expenditures for additions to property, plant and equipment and acquisitions were:

$16.7 million in 2003 (net of discontinued operations), which includes $12.0 million of capital expenditures for our acquisition of the Carmen gathering system which is part of our Eagle Chief gathering system and $3.5 million for capital expansion of the Matli gathering system which included construction of the Matli processing plant and a compressor station and $1.2 million for other assets.

$5.1 million in 2002 (net of discontinued operations), which includes $1.8 million of capital expenditures for building new gathering facilities in Mississippi and $3.3 million of capital expenditures for continued expansion of our existing gathering systems.

Cash flows from financing activities. Net cash provided by (used in) financing activities was ($2.9) million for 2004 and $13.2 million for 2003. For 2004, cash used in financing activities was primarily attributable to our net repayment of $1.9 million in long-term debt. Cash provided by financing activities of $13.2 million for 2003 was attributable to net borrowings of long-term debt primarily for financing the acquisition of the Carmen gathering system. Net cash provided by (used in) financing activities was $0.5 million for the year ended December 31, 2002 as a result of net borrowings for capital expenditures.

Net Assets Acquired from Hiland Partners, LLC Twelve Months Ended December 31, 2004 Compared to Twelve Months Ended December 31, 2003 and Twelve Months Ended December 31, 2003 to Twelve Months Ended December 31, 2002

Cash flows from operating activities. Net cash provided by operating activities was $7.0 million and $5.4 million for 2004 and 2003, respectively, an increase of $1.7 million. Total segment margin increased by $2.0 million and the increase was attributable to increases in our total segment margin as a result of an increase in natural gas and NGL prices and our compression margin as a result of expansion of our compression facilities in the second half of 2003.

Net cash provided by operating activities was $5.4 million and $3.0 million for the year ended December 31, 2003 and 2002, respectively, an increase of $2.4 million. Total segment margin increased $3.5 million for the year ended December 31, 2003 as compared to the year ended December 31, 2002. The increase in total segment margin is primarily attributable to the start-up of our compression segment. Our compression equipment was acquired in December 2002.

Cash flows used in investing activities. Net cash used in investing activities was $24.8 million for 2004 and $5.1 million for 2003. The net cash used in investing activities for 2004 includes $24.4 million related to construction of the Bakken gathering system (which was not contributed to us in connection with our initial public offering). Net cash used in investing activities was $5.1 million and $12.1 million and for the years ended December 31, 2003 and 2002, respectively. Capital expenditures for additions to property, plant and equipment and additions to assets for lease were:

$5.1 million in 2003, which includes $4.5 million for compressors purchased and leased to Continental Resources, Inc. to be used in their secondary recovery project and $0.6 million for other assets.

$12.5 million in 2002, which includes $12.0 million for compressors purchased and leased to Continental Resources, Inc. to be used in their secondary recovery project.

Cash flows used in financing activities. Net cash provided by financing activities was $18.0 million for 2004 which was attributable to our net borrowings to finance the construction of the Bakken gathering system. Net cash used in financing activities was $0.3 million for 2003 which was attributable to our repayment of long-term debt. Net cash provided by financing activities was $9.6 million for the year ended December 31, 2002, which was used to acquire compressors that are leased to Continental Resources, Inc. for use in their secondary recovery project.

Capital Requirements

The midstream energy business is capital intensive, requiring significant investment to maintain and upgrade existing operations. Our capital requirements have consisted primarily of, and we anticipate will continue to be:

- maintenance capital expenditures, which are capital expenditures made to replace partially or fully depreciated assets to maintain the existing operating capacity of our assets and to extend their useful lives, or other capital expenditures that are incurred in maintaining existing system volumes and related cash flows; and

- expansion capital expenditures such as those to acquire additional assets to grow our business, to expand and upgrade gathering systems, processing plants, treating facilities and fractionation facilities and to construct or acquire similar systems or facilities.

Given our objective of growth through acquisitions and expansions, we anticipate that we will continue to invest significant amounts of capital to grow and acquire assets. We actively consider a variety of assets for potential acquisitions. For a discussion of the primary factors we consider in deciding whether to pursue a particular acquisition, please read " Our Growth Strategy Acquisitions."

We believe that cash generated from the operations of our business will be sufficient to meet anticipated maintenance capital expenditures, for which we have budgeted $2.0 million in 2005. We anticipate that expansion capital expenditures will be funded through long-term borrowings or other debt financings and/or equity capital offerings. See "Credit Facility" below for information related to the credit agreement we entered into in February 2005.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of September 30, 2005, is as follows:

	Payment Due by Period				
Type of Obligation	**Total Obligation**	**Remainder Due in 2005**	**Due in 2006**	**Due in 2007-2008**	**Thereafter**
			(in thousands)		
Senior secured revolving credit facility(1)	$ 93,700	$	$	$ 93,700	$
Operating leases	465	22	98	217	128
Total contractual cash obligations	$ 94,165	$ 22	$ 98	$ 93,917	$ 128

(1) For a discussion of our senior secured revolving credit facility, please read " Credit Facility" below.

In addition to the contractual obligations noted in the table above, as of September 30, 2005, we have forward sales contracts to (a) sell approximately 50,000 MMBtu of natural gas per month through December 2007 with weighted average fixed prices per MMBtu of $4.53, $4.47 and $4.49, respectively, for years 2005 through 2007 and (b) sell approximately 50,000 MMBtu of natural gas per month from October 2005 through December 2006 with weighted average fixed prices per MMBtu of $9.52. Such contracts have been designated as normal sales under SFAS No. 133 and are therefore not marked to market as derivatives.

Badlands Expansion Project. On November 8, 2005, we entered into a new 15-year definitive gas purchase agreement with Continental Resources, Inc. under which we will gather, treat and process additional natural gas, which is produced as a by-product of Continental Resources' secondary oil recovery operations, in the areas specified by the contract. In order to fulfill our obligations under the agreement, we intend to expand our Badlands gas gathering system and processing plant located in

Bowman County, North Dakota. This expansion project will include the construction of a 40,000 Mcf/d nitrogen rejection plant and the expansion of our existing Badlands field gathering infrastructure. The expansion project, which is targeted for completion in the 4th quarter of 2006, is expected to cost approximately $40 million, which we intend to fund using our existing bank credit facility. Moreover, we expect to spend an additional $9.5 million in 2007 to expand the system. The cost to expand the system may exceed our expected costs if our assumptions as to construction costs or other factors are incorrect or as a result of other events that are beyond our control.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of September 30, 2005.

Credit Facility

Concurrently with the closing of our initial public offering, we entered into a three-year $55.0 million senior secured revolving credit facility. MidFirst Bank, a federally chartered savings association located in Oklahoma City, Oklahoma, is a lender and serves as administrative agent under this facility. On September 26, 2005, concurrently with the closing of the Bakken acquisition, we amended this facility to increase our borrowing capacity under the facility to $125.0 million. The facility currently consists of:

- a $117.5 million senior secured revolving credit facility to be used for funding acquisitions and other capital expenditures, issuance of letters of credit and general corporate purposes (the "revolving acquisition facility"); and

- a $7.5 million senior secured revolving credit facility to be used for working capital and to fund distributions (the "revolving working capital facility").

In addition, the revolving acquisition facility allows for the issuance of letters of credit of up to $5.0 million in the aggregate. The credit facility will mature in February 2008. At that time, the agreement will terminate and all outstanding amounts thereunder will be due and payable.

Our obligations under the credit facility are secured by substantially all of our assets and guaranteed by us and all of our subsidiaries, other than our operating company, which is the borrower under the credit facility. The credit facility is non-recourse to our general partner.

Indebtedness under the credit facility will bear interest, at our option, at either (i) an Alternate Base Rate plus an applicable margin ranging from 50 to 175 basis points per annum or (ii) LIBOR plus an applicable margin ranging from 150 to 275 basis points per annum based on our ratio of total debt to EBITDA. The Alternate Base Rate is a rate per annum equal to the greatest of (a) the Prime Rate in effect on such day, (b) the base CD rate in effect on such day plus 1.50% and (c) the Federal Funds effective rate in effect on such day plus $^1/_2$ of 1%. A letter of credit fee will be payable for the aggregate amount of letters of credit issued under the credit facility at a percentage per annum equal to 1.0%. An unused commitment fee ranging from 30 to 50 basis points per annum based on our ratio of total debt to EBITDA will be payable on the unused portion of the credit facility.

The credit facility prohibits us from making distributions to unitholders if any default or event of default, as defined in the credit facility, has occurred and is continuing or would result from the distribution. In addition, the credit facility contains various covenants that limit, among other things, subject to certain exceptions and negotiated "baskets," our ability to:

- incur indebtedness;

- grant liens;

- make certain loans, acquisitions and investments;

- make any material changes to the nature of our business;

- amend our material agreements, including the Omnibus Agreement; or
- enter into a merger, consolidation or sale of assets.

The credit facility also contains covenants requiring us to maintain:

- a maximum total debt to EBITDA ratio of 4.5:1.0 for the fiscal quarter ended September 30, 2005 and the fiscal quarter ending December 31, 2005; thereafter a maximum total debt to EBITDA ratio of 4.0:1.0;
- a minimum interest coverage ratio of 3.0:1.0; and
- minimum tangible net worth of $15.0 million for the fiscal quarter ended September 30, 2005 and the fiscal quarter ending December 31, 2005; thereafter a minimum tangible net worth of $40.0 million.

Upon the occurrence of an event of default under the credit facility, the lenders may, among other things, be able to accelerate the maturity of the credit facility and exercise other rights and remedies as set forth in the credit facility. Each of the following will be an event of default:

- failure to pay any principal when due or any interest, fees or other amount within 3 business days of when due;
- failure of any representation or warranty to be true and correct in all material respects;
- failure to perform or otherwise comply with the covenants in the credit facility or other loan documents, in certain cases subject to certain grace periods;
- default by us or any of our subsidiaries on the payment of any other indebtedness in excess of $1.0 million, or any default in the performance of any obligation or condition with respect to such indebtedness beyond the applicable grace period if the effect of the default is to permit or cause the acceleration of the indebtedness;
- bankruptcy or insolvency events involving us, our general partner or our subsidiaries;
- material default by any party to any material agreement, which is not cured within the time period specified in the material agreement for cure, that is reasonably expected to have a material adverse effect;
- the entry, and failure to pay or contest in good faith, of one or more adverse judgments in an aggregate amount of $500,000 or more in excess of third party insurance coverage;
- a change of control (as defined in the credit facility); and
- invalidity of any loan documentation.

The credit facility limits distributions to our unitholders to Available Cash, and borrowings to fund such distributions are only permitted under the revolving working capital facility. The revolving working capital facility is subject to an annual "clean-down" period of 15 consecutive days in which the amount outstanding under the revolving working capital facility is reduced to zero.

As of September 30, 2005, we had $93.7 million outstanding under the credit facility, substantially all of which was incurred to fund the Bakken acquisition.

Recent Accounting Pronouncements

In October 1995, the FASB issued SFAS No. 123 "Share-Based Payments" which was revised in December 2004 (collectively, "FASB 123R"). FASB 123R requires that the compensation cost relating to share-based payment transactions be recognized in financial statements and that cost will be measured based on the fair value of the equity or liability instruments issued. The effect of the standard will be to require entities to measure the cost of employee services received in exchange for stock or unit options based on the grant-date fair value of the award, and to recognize the cost over the period the employee is required to provide services for the award. In accordance with SEC Release 33-8568, we will adopt SFAS 123R as of the first interim period beginning on or after January 1, 2006. We expect to apply the statement using the permitted modified prospective method, presenting all interim periods of the year of adoption, beginning January 1, 2006. We had 166,000 options outstanding as of September 30, 2005.

In March 2005, the FASB issued Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations*, which clarifies when an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation and will be effective for fiscal years ending after December 15, 2005, with early adoption encouraged. We are reviewing this interpretation to determine what, if any, effect this will have on our financial condition and results of operations.

Significant Accounting Policies and Estimates

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve the implementation and interpretation of existing rules, and the use of judgment applied to the specific set of circumstances existing in our business. We make every effort to properly comply with all applicable rules on or before their adoption, and we believe the proper implementation and consistent application of the accounting rules are critical. For further details on our accounting policies, you should read Note 1 of the accompanying Notes to Financial Statements.

Asset Retirement Obligations. SFAS No. 143 "Accounting for Asset Retirement Obligations" requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement cost is allocated to expense using a systematic and rational method and the liability is accreted to measure the change in liability due to the passage of time. The primary impact of this standard relates to our estimated costs for dismantling and site restoration of certain of our plants and pipelines. Estimating future asset retirement obligations requires us to make estimates and judgments regarding timing, existence of a liability, as well as what constitutes adequate restoration. We use the present value of estimated cash flows related to our asset retirement obligation to determine the fair value, generally as estimated by third party consultants. The present value calculation requires us to make numerous assumptions and judgments, including the ultimate costs of dismantling and site restoration, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation liability, a corresponding adjustment will be required to the related asset. We believe the estimates and judgments reflected in our financial statements are reasonable but are necessarily subject to the uncertainties we have just described. Accordingly, any significant variance in any of the above assumptions or factors could materially affect our cash flows.

Impairment of Long-Lived Assets. In accordance with Statement of Financial Accounting Standards (SFAS) No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, we evaluate our long-lived assets of identifiable business activities for impairment when events or changes in circumstances indicate, in management's judgment, that the carrying value of such assets may not be recoverable. The determination of whether impairment has occurred is based on management's estimate of undiscounted future cash flows attributable to the assets as compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value for the assets and recording a provision for loss if the carrying value is greater than fair value. For assets identified to be disposed of in the future, the carrying value of these assets is compared to the estimated fair value less the cost to sell to determine if impairment is required. Until the assets are disposed of, an estimate of the fair value is re-determined when related events or circumstances change.

When determining whether impairment of one of our long-lived assets has occurred, we must estimate the undiscounted cash flows attributable to the asset or asset group. Our estimate of cash flows is based on assumptions regarding the volume of reserves providing asset cash flow and future NGL product and natural gas prices. The amount of reserves and drilling activity are dependent in part on natural gas prices. Projections of reserves and future commodity prices are inherently subjective and contingent upon a number of variable factors, including, but not limited to:

- changes in general economic conditions in regions in which our products are located;
- the availability and prices of NGL products and competing commodities;
- the availability and prices of raw natural gas supply;
- our ability to negotiate favorable marketing agreements;
- the risks that third party oil and gas exploration and production activities will not occur or be successful;
- our dependence on certain significant customers and producers of natural gas; and
- competition from other midstream service providers, processors, including major energy companies.

Any significant variance in any of the above assumptions or factors could materially affect our cash flows, which could require us to record an impairment of an asset.

In December 2003, as a result of volume declines at gathering facilities located in Texas, Mississippi and Wyoming, Continental Gas, Inc. recognized an impairment charge of $1.5 million. No impairment charges were recognized during each of the years ended December 31, 2004 and 2002 and the nine months ended September 30, 2005.

Revenue Recognition. Revenues for sales of natural gas and NGLs product sales are recognized at the time the product is delivered and title is transferred. Revenues from compressor leasing operations were recognized when earned ratably as due under the lease. Revenues from oil and gas production (discontinued operations) were recorded in the month produced and title was transferred to the purchaser. Under the compression services agreement that we entered into with Continental Resources, Inc. in connection with our initial public offering, revenues are recognized when the services under the agreement are performed. For a description of this service agreement, please read " Our Contracts Compression Services Agreement."

Derivatives. We utilize derivative financial instruments to reduce commodity price risks. We do not hold or issue derivative financial instruments for trading purposes. Statement of Financial Accounting Standards (or SFAS) No. 133, Accounting for Derivative Instruments and Hedging Activities, which was amended in June 2000 by SFAS No. 138 and in May 2003 by SFAS No. 149, establishes accounting and reporting standards for derivative instruments and hedging activities. It requires that an entity recognize all derivatives as either assets or liabilities in the statement of financial condition and measure those instruments at fair value. Derivatives that are not designated as hedges are adjusted to fair value through income. If the derivative is designated as a hedge, depending upon the nature of the hedge, changes in the fair value of the derivatives are either offset against the fair value of assets, liabilities or firm commitments through income, or recognized in other comprehensive income until the hedged item is recognized in income. The ineffective portion of a derivative's change in fair value is immediately recognized into income. If a derivative no longer qualifies for hedge accounting the amounts in accumulated other comprehensive income will be immediately charged to operations.

Quantitative and Qualitative Disclosures about Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. The principal market risk to which we are exposed is commodity price risk for natural gas and NGLs. We also incur, to a lesser extent, risks related to interest rate fluctuations. We do not engage in commodity energy trading activities.

Commodity Price Risks. Our profitability is affected by volatility in prevailing NGL and natural gas prices. Historically, changes in the prices of most NGL products have generally correlated with changes in the price of crude oil. NGL and natural gas prices are volatile and are impacted by changes in the supply and demand for NGLs and natural gas, as well as market uncertainty. For a discussion of the volatility of natural gas and NGL prices, please read "Risk Factors Risk Factors Related to our Business Our cash flow is affected by the volatility of natural gas and NGL product prices, which could adversely affect our ability to make distributions to unitholders." To illustrate the impact of changes in prices for natural gas and NGLs on our operating results, we have provided the table below, which reflects, for the nine months ended September 30, 2005, the impact on our total segment margin of a $0.01 per gallon change (increase or decrease) in NGL prices coupled with a $0.10 per MMBtu change (increase or decrease) in the price of natural gas. The magnitude of the impact on total segment margin of changes in natural gas and NGL prices presented may not be representative of the magnitude of the impact on total segment margin for different commodity prices or contract portfolios. Natural gas prices can also affect our profitability indirectly by influencing the level of drilling activity and related opportunities for our services.

NGL Price Change ($/gal)	Natural Gas Price Change ($/MMBtu) $0.10	$(0.10)
$ 0.01	$ 196,000	$ 83,000
$(0.01)	$ (1,000)	$ (111,000)

We manage this commodity price exposure through an integrated strategy that includes management of our contract portfolio, optimization of our assets and the use of derivative contracts. In October 2005, we executed swap contracts relating to a portion of our residue gas sales from our Bakken gathering system that settle against natural gas market prices. As a result, we have hedged a portion of our expected exposure to natural gas prices in 2006 and 2007 at the Bakken gathering system. We continually monitor our hedging and contract portfolio and expect to continue to adjust our hedge position as conditions warrant.

The following table provides information about our derivative instruments:

Natural Gas Swaps	Monthly Volume (MMBtu)	Price ($/MMBtu)
May 2006 - December 2006	40,000	$ 8.78
January 2007 - October 2007	40,000	$ 7.83

In addition to the derivative instruments noted in the table above, as of September 30, 2005, we have forward sales contracts to (a) sell approximately 50,000 MMBtu of natural gas per month through December 2007 with weighted average fixed prices per MMBtu of $4.53, $4.47 and $4.49, respectively, for years 2005 through 2007 and (b) sell approximately 50,000 MMBtu of natural gas per month from October 2005 through December 2006 with weighted average fixed prices per MMBtu of $9.52. Such contracts have been designated as normal sales under SFAS No. 133 and are therefore not marked to market as derivatives.

Interest Rate Risk. We are exposed to changes in interest rates as a result of our credit facility, which has floating interest rates. As of September 30, 2005, we had approximately $93.7 million of indebtedness outstanding under our credit facility. The impact of a 100 basis point increase in interest rates on this amount of debt would result in an increase in interest expense, and a corresponding decrease in net income of approximately $0.9 million annually.

Credit Risk. Counterparties pursuant to the terms of their contractual obligations expose us to potential losses as a result of nonperformance. OGE Energy Resources, Inc. and BP Energy Company were our largest customers for the nine months ended September 30, 2005, accounting for approximately 24.6% and 18.9%, respectively, of our revenues. Consequently, changes within one or both of these companies' operations have the potential to impact, both positively and negatively, our credit exposure.

BUSINESS

Overview

We are a growth oriented midstream energy partnership engaged in gathering, compressing, dehydrating, treating, processing and marketing natural gas, and fractionating, or separating NGLs. We also provide air compression and water injection services to an oil and gas exploration and production company for its use in its oil and gas secondary recovery operations. Our operations are primarily located in the Mid-Continent and Rocky Mountain regions of the United States. In our midstream segment, we connect the wells of natural gas producers in our market areas to our gathering systems, treat natural gas to remove impurities, process natural gas for the removal of NGLs, fractionate NGLs into NGL products and provide an aggregate supply of natural gas and NGL products to a variety of natural gas transmission pipelines and markets. In our compression segment, we provide compressed air and water to Continental Resources. Continental Resources uses the compressed air and water in its oil and gas secondary recovery operations in North Dakota by injecting them into its oil and gas reservoirs to increase oil and gas production from those reservoirs. This increased production of natural gas flows through our midstream systems.

Our midstream assets consist of eight natural gas gathering systems with approximately 1,124 miles of gas gathering pipelines, five natural gas processing plants, three natural gas treating facilities and three NGL fractionation facilities. Our compression assets consist of two air compression facilities and a water injection plant.

We commenced our midstream operations in 1990 when Continental Gas, Inc., then a subsidiary of Continental Resources, constructed the Eagle Chief gathering system in northwest Oklahoma. Since 1990, we have grown through a combination of building gas gathering and processing assets in areas where Continental Resources has active exploration and production assets and through acquisitions of existing systems which we have then expanded. Since inception, we have constructed 322 miles of natural gas gathering pipelines, three natural gas processing plants, two treating facilities and one fractionation facility. In addition, our management team designed and constructed the Bakken gathering system that we recently acquired from an affiliate of our general partner, which consists of 256 miles of gas gathering pipeline, a natural gas processing plant, two compressor stations and one fractionation facility. We have also acquired 546 miles of natural gas gathering pipelines, one natural gas processing plant, one treating facility and one fractionation facility. Our pro forma total segment margin for the year ended December 31, 2004 and for the nine months ended September 30, 2005 was $25.5 million and $26.4 million, respectively.

Recent Developments

Bakken Acquisition. Effective September 1, 2005, we consummated the Bakken acquisition pursuant to which we acquired the outstanding membership interests in Hiland Partners, LLC, an Oklahoma limited liability company, for approximately $92.7 million in cash, $35.0 million of which was used to retire outstanding Hiland Partners, LLC indebtedness. Hiland Partners, LLC's principal asset is the Bakken gathering system located in eastern Montana. Pursuant to an option contained in the omnibus agreement we entered into with Hiland Partners, LLC and Harold Hamm and his affiliates in connection with our initial public offering, Hiland Partners, LLC granted us an exclusive two-year option to purchase the Bakken gathering system at fair market value at the time of purchase. A mutually-agreed-upon investment banking firm determined the fair market value of the Bakken gathering system, and the conflicts committee of the board of directors of our general partner, consisting of its independent directors, approved the transaction.

The Bakken gathering system is located in an area where a number of exploration and production companies are actively developing crude oil and associated natural gas reserves from the Bakken shale formation. As of September 30, 2005, the Bakken gathering system consisted of approximately 256 miles of gas gathering pipeline, a natural gas processing plant, two compressor stations, which are comprised of three units with an aggregate of approximately 4,434 horsepower, and one fractionation facility. The Bakken processing plant and a portion of the gathering system became operational on November 8, 2004 and the system's peak and average throughput rates during the month of September 2005 were approximately 14,475 Mcf/d and 13,100 Mcf/d, respectively. The gathering system has an initial capacity of approximately 25,000 Mcf/d.

Bank Credit Facility. To facilitate the closing of the Bakken acquisition, we amended our senior revolving credit facility to increase our borrowing capacity under the facility from $55.0 million to $125.0 million, consisting of a $117.5 million acquisition facility and a $7.5 million working capital facility. We used a portion of this increased capacity to fund the Bakken acquisition. Upon completion of this offering, we expect to have available capacity of approximately $88.0 million under our acquisition facility for future borrowings. For a more complete description of our credit facility, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Credit Facility."

Distribution Increase. On November 14, 2005, we paid a cash distribution of $0.5125 per unit, or $2.05 per unit on an annualized basis, on our common and subordinated units for the quarter ended September 30, 2005. This distribution represented an increase of 11% from our distribution of $0.4625 per unit for the second quarter of 2005.

As a result of the Bakken acquisition, our management intends to recommend to the board of directors of our general partner an additional quarterly distribution increase of $0.075 per quarter, or $0.30 per unit on an annualized basis, for the first full quarter following the closing of the acquisition. Such an increase would result in a quarterly distribution of $0.5875 per unit, which equals an annualized distribution rate of $2.35 per unit. Subject to the approval of the board of directors of our general partner and the absence of any material adverse developments or potentially attractive opportunities that would make such an increase inadvisable, we expect this increase to be reflected in our distribution declared for the fourth quarter of 2005.

Under our partnership agreement, generally our general partner is entitled to 15% of the amount we distribute to each unitholder in excess of $0.495 per unit per quarter up to $0.5625 per unit per quarter, and 25% of the amount we distribute to each unitholder in excess of $0.5625 per unit per quarter up to $0.675 per unit per quarter.

Badlands Expansion Project. On November 8, 2005, we entered into a new 15-year definitive gas purchase agreement with Continental Resources, Inc. under which we will gather, treat and process additional natural gas, which is produced as a by-product of Continental Resources' secondary oil recovery operations, in the areas specified by the contract. In return, we will receive 50% of the proceeds attributable to residue gas and natural gas liquids sales as well as certain fixed fees associated with gathering and treating the natural gas, including a $0.60 per Mcf fee for the first 36 Bcf of natural gas gathered. The board of directors, as well as the conflicts committee of the board of directors, of our general partner have approved the agreement.

In order to fulfill our obligations under the agreement, we intend to expand our Badlands gas gathering system and processing plant located in Bowman County, North Dakota. This expansion project will include the construction of a 40,000 Mcf/d nitrogen rejection plant and the expansion of our existing Badlands field gathering infrastructure. The expansion project, which is targeted for completion in the 4th quarter of 2006, is expected to cost approximately $40 million, which we intend to fund using our existing bank credit facility. Moreover, we expect to spend an additional $9.5 million in 2007 to expand the system.

Board Member Selections. On May 11, 2005, we announced that the board of directors of our general partner had appointed Rayford T. Reid as a director. Mr. Reid was also named to the compensation committee of the board of directors. On October 3, 2004, we announced that the board of directors of our general partner had appointed Shelby E. Odell as director. For a more complete description of the board of directors of our general partner, please read "Management Directors and Executive Officers of Hiland Partners GP, LLC."

Midstream Segment

Our midstream operations consist of the following:

- gathering and compressing natural gas to facilitate its transportation to our processing plants, third party pipelines, utilities and other consumers;
- dehydrating natural gas to remove water from the natural gas stream to meet pipeline quality specifications;
- treating natural gas to remove or reduce impurities such as carbon dioxide, hydrogen sulfide and other contaminants to ensure that the natural gas meets pipeline quality specifications;
- processing natural gas to extract NGLs and selling the resulting residue natural gas and, in most cases, the NGLs; and
- fractionating a portion of our NGLs into a mix of NGL products, including ethane, propane and a mixture of butane and natural gasoline, and selling these NGL products to third parties.

Our midstream assets include the following:

- *Eagle Chief Gathering System.* The Eagle Chief gathering system is a 554-mile gas gathering system located in northwest Oklahoma that gathers, compresses, dehydrates and processes natural gas. The system includes the Eagle Chief processing plant and four compressor stations. We constructed the Eagle Chief gathering system in 1990 and constructed the Eagle Chief processing plant in 1995. We acquired the Carmen gathering system in August 2003, which consists solely of gathering lines to expand our Eagle Chief gathering system. Our Eagle Chief gathering system has a capacity of 30,000 Mcf/d and average throughput was approximately 20,370 Mcf/d for the nine months ended September 30, 2005. The system represented approximately 27.6% of our pro forma total segment margin for the nine months ended September 30, 2005.
- *Bakken Gathering System.* The Bakken gathering system is a 256-mile gas gathering system located in Richland County, Montana that gathers, compresses, dehydrates and processes natural gas. This system includes the Bakken processing plant, two compressor stations, which are comprised of three units with an aggregate of approximately 4,434 horsepower and one fractionation facility. We acquired the Bakken gathering system and the Bakken processing plant in September 2005. Our Bakken gathering system has capacity of 25,000 Mcf/d and average throughput was approximately 8,260 Mcf/d for the nine months ended September 30, 2005. The system represented approximately 22.8% of our pro forma total segment margin for the nine months ended September 30, 2005.
- *Worland Gathering System.* The Worland gathering system is a 151-mile gas gathering system located in central Wyoming that gathers, compresses, dehydrates, treats and processes natural gas, and fractionates NGLs. The system includes the Worland processing plant, four compressor stations, one treating facility and one fractionation facility. We acquired the Worland gathering system and the Worland processing plant in 2000. Our Worland gathering system has a capacity of 8,000 Mcf/d and average throughput was approximately 3,110 Mcf/d for the nine months ended September 30, 2005. The system represented approximately 14.9% of our pro forma total segment margin for the nine months ended September 30, 2005.
- *Badlands Gathering System.* The Badlands gathering system is a 108-mile gas gathering system located in southwest North Dakota that gathers, compresses, dehydrates, treats and processes

natural gas, and fractionates NGLs. The system includes the Badlands processing plant, four compressor stations, one treating facility and one fractionation facility. We constructed the Badlands gathering system and the Badlands processing plant in 1997. Our Badlands gathering system has a capacity of 5,000 Mcf/d and average throughput was approximately 3,080 Mcf/d for the nine months ended September 30, 2005. The system represented approximately 14.8% of our pro forma total segment margin for the nine months ended September 30, 2005.

Matli Gathering System. The Matli gathering system is a 37-mile gas gathering system located in central Oklahoma that gathers, compresses, dehydrates, treats and processes natural gas. The system includes the Matli processing plant, two compressor stations and one treating facility. We constructed the Matli gathering system in 1999 and constructed the Matli processing plant in 2003. Our Matli gathering system has a capacity of 20,000 Mcf/d and average throughput was approximately 14,640 Mcf/d for the nine months ended September 30, 2005. The system represented approximately 5.2% of our pro forma total segment margin for the nine months ended September 30, 2005.

Other Systems. We also own three natural gas gathering systems located in Texas, Mississippi and Oklahoma. These systems represented approximately 2.0% of our pro forma total segment margin for the nine months ended September 30, 2005.

The table set forth below contains certain information regarding our gathering systems as of or for the nine months ended September 30, 2005.

Asset	Type	Length (Miles)	Approximate Wells Connected	Throughput Capacity (Mcf/d)	Average Throughput (Mcf/d)	Utilization of Capacity
Eagle Chief gathering system	Gathering pipelines	554	368	30,000	20,370	67.9%
	Processing plant			25,000	20,370	81.5%
Bakken gathering system	Gathering pipelines	256	131	25,000	8,260	33.0%
	Processing plant			25,000	8,260	33.0%
	Fractionation facility (Bbls/d)			4,600	1,582	34.4%
Worland gathering system	Gathering pipelines	151	94	8,000	3,110	38.9%
	Processing plant			8,000	3,110	38.9%
	Treating facility			8,000	3,110	38.9%
	Fractionation facility (Bbls/d)			650	355	54.6%
Badlands gathering system	Gathering pipelines	108	96	5,000	3,080	61.6%
	Processing plant			5,000	3,080	61.6%
	Treating facility			7,100	3,080	43.4%
	Fractionation facility (Bbls/d)			600	375	62.5%
Matli gathering system	Gathering pipelines	37	38	20,000	14,640	73.2%
	Processing plant			10,000	5,010	50.1%
	Treating facility			10,000	9,510	95.1%
Other Systems	Gathering pipelines	18	29	7,000	3,980	56.9%
	Total	1,124	756			

Compression Segment

We provide air and water compression services to Continental Resources for use in its oil and gas secondary recovery operations under a four-year, fixed-fee contract (which we entered into in connection with our initial public offering) at our Cedar Hills compression facility, our Horse Creek compression facility and our water injection plant located next to our Cedar Hills compression facility. These assets are located in North Dakota in close proximity to our Badlands gathering system. At the compression facilities, we compress air to pressures in excess of 4,000 pounds per square inch, and at the water injection plant, we pump water to pressures in excess of 2,000 pounds per square inch. The air and water are delivered at the tailgate of our facilities into pipelines operated by Continental Resources and are ultimately utilized by Continental Resources in its oil and gas secondary operations.

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The natural gas produced by Continental Resources flows through our Badlands gathering system. Our compression segment represented approximately 12.7% of our pro forma total segment margin for the nine months ended September 30, 2005.

Competitive Strengths

Based on the following competitive strengths, we believe that we are well positioned to compete in our operating regions:

We have expertise in developing midstream systems. Since our inception in 1990, our management has demonstrated the ability to identify midstream opportunities and build or acquire the assets needed to capitalize on those opportunities. To date, we have built or acquired eight gas gathering systems. A majority of our growth has come from gas gathering systems and plants that we have constructed, including the Eagle Chief, Bakken, Badlands and Matli gathering systems. Since building the Eagle Chief gathering system, we have expanded that system by constructing 177 miles of gathering pipeline and acquiring approximately 377 miles of gathering pipeline in five separate transactions. We have also utilized acquisitions such as our purchase of the 151-mile Worland gathering system in 2000 as a way to establish a presence in new areas.

Substantially all of our facilities are modern. We built our Eagle Chief processing plant in 1995, our Badlands processing plant in 1997 and our Matli processing plant in 2003. In addition, the previous owner replaced a substantial portion of the equipment on our Worland gathering system, including the Worland processing plant, the treating facility and the fractionation facility, in 1997. Additionally, our Bakken gathering system was constructed in 2004. The condition of our facilities directly benefits our margins and our ability to attract new supplies of natural gas by offering operational efficiency and reliability. Additionally, our facilities generally require less maintenance and are subject to fewer environmental liabilities and permitting issues than older facilities.

Our assets are strategically located in major natural gas supply areas and have available capacity. Our assets are strategically located in the Mid-Continent and Rocky Mountain regions of the United States. These regions are generally characterized by significant current drilling activity, which provides us with attractive opportunities to access newly developed natural gas supplies. Several of these regions are experiencing increased levels of exploration, development and production activities as a result of recent high commodity prices, new discoveries and the implementation of secondary recovery techniques. In addition, substantially all of our assets have available capacity. We believe that our presence in these regions, together with the available capacity of our assets and limited competitive alternatives, provides us with a competitive advantage in capturing new supplies of natural gas.

We provide an integrated and comprehensive package of midstream services. We provide a broad range of midstream services to natural gas producers, including natural gas gathering, compression, dehydration, treating, processing and marketing and the fractionation of NGLs. We believe our ability to provide all of these services gives us an advantage in competing for new supplies of natural gas because we can provide all of the services producers, marketers and others require to connect their natural gas quickly and efficiently.

We have the financial flexibility to pursue growth projects. Our $125.0 million bank credit facility contains a $117.5 million revolving facility for acquisitions and capital expenditures, of which approximately $88.0 million will be available upon the closing of this offering, and a $7.5 million working capital facility. We believe the available capacity under our credit facility combined with our expected ability to access the capital markets will provide us with a flexible financial structure that will facilitate our strategic expansion and acquisition strategies.

We have significant experience operating our assets and a knowledgeable senior management team. Our senior management team has been actively involved in the construction and development of substantially all of our primary assets. Our senior management team has an average of 25 years of energy industry experience.

Business Strategies

Our management team is committed to increasing the amount of cash available for distribution per unit by executing the following strategies:

Engaging in construction and expansion opportunities. We intend to leverage our existing infrastructure and customer relationships by constructing and expanding systems to meet new or increased demand for our midstream services. These projects include expansion of existing systems and construction of new facilities, such as our Badlands expansion project.

Pursuing complementary acquisitions. We intend to make complementary acquisitions of midstream assets in our operating areas that provide opportunities to expand or increase the utilization of our existing assets. We intend to pursue acquisitions that we believe will allow us to capitalize on our existing infrastructure, personnel, and producer and customer relationships to provide an integrated package of services. In addition, we may pursue selected acquisitions in new geographic areas to the extent they present growth opportunities similar to those we are pursuing in our existing areas of operations.

Increasing volumes on our existing assets. Our gathering systems have excess capacity, which provides us with opportunities to increase throughput volume with minimal incremental costs and thereby increase cash flow. We intend to aggressively market our services to producers in order to connect new supplies of natural gas, increase volumes and more fully utilize our capacity, particularly in our areas experiencing an increased level of natural gas exploration, development and production activities.

Taking measures that reduce our exposure to commodity price risk. Because of the significant volatility of natural gas and NGL prices, we attempt to operate our business in a manner that allows us to mitigate the impact of fluctuations in commodity prices. In order to reduce our exposure to commodity price risk, we intend to pursue fee-based arrangements, where market conditions permit, and to enter into forward sales contracts or hedging arrangements to cover a portion of our operations that are not conducted under fee-based arrangements. In addition, when processing margins (or the difference between NGL sales prices and the cost of natural gas) are unfavorable, we can elect not to process natural gas at our Eagle Chief processing plant and deliver the unprocessed natural gas directly into the interstate pipeline. Collectively, these strategies should contribute to more stable cash flows.

Industry Overview

The midstream natural gas industry is the link between the exploration and production of natural gas and the delivery of its components to end-use markets and consists of natural gas gathering, compression, dehydration, treating, processing, fractionation and transportation. The midstream industry is generally characterized by regional competition based on the proximity of gathering systems and processing plants to natural gas producing wells.

The following diagram illustrates the natural gas gathering, dehydration, compression, treating, processing, fractionation and transportation processes. We provide all of these services other than transportation to our customers.

Demand for natural gas. Natural gas continues to be a critical component of energy consumption in the United States. According to the Energy Information Administration, or the EIA, total domestic consumption of natural gas is expected to increase by over 2.3% per annum, on average, to 25.4 trillion cubic feet, or Tcf, by 2010, from an estimated 22.1 Tcf consumed in 2004, representing approximately 23.5% of all total end-user energy requirements by 2010. During the last three years, the United States has on average consumed approximately 22.4 Tcf per year, with average domestic production of approximately 18.6 Tcf per year during the same period.

The industrial and electricity generation sectors are the largest users of natural gas in the United States. During the last three years, these sectors accounted for approximately 60.8% of the total natural gas consumption in the United States. According to the EIA, consumption in the industrial and electricity generation sectors is expected to increase by over 2.8% per annum, on average, to 15.8 Tcf in 2010 from an estimated 13.4 Tcf in 2004.

Natural gas reserves and production. As of December 31, 2003, operators in the United States had 189.0 Tcf of dry, or "lean," natural gas reserves and 7,459 MMBbls of NGL reserves, or "rich" natural gas reserves. Natural gas is described as lean or rich depending on its content of heavy components or liquids. These terms are relative, but as used throughout this prospectus, rich gas may contain as much as five to six gallons or more of NGLs per Mcf, whereas lean gas usually contains less than two gallons of NGLs per Mcf. Driven by growth in natural gas demand, domestic natural gas production is projected to increase from an estimated 18.5 Tcf per year to 20.2 Tcf per year between 2004 and 2010.

Natural gas gathering and compression. The natural gas gathering process begins with the drilling of wells into gas bearing rock formations. Once a well has been completed, the well is connected to a gathering system. Gathering systems generally consist of a network of small diameter pipelines that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission. Gathering systems are operated at design pressures that will maximize the total throughput from all connected wells.

Since wells produce at progressively lower field pressures as they age, it becomes increasingly difficult to deliver the remaining production in the ground against a higher pressure that exists in the connecting gathering system. Natural gas compression is a mechanical process in which a volume of gas at an existing pressure is compressed to a desired higher pressure, allowing gas that no longer naturally flows into a higher pressure downstream pipeline to be brought to market. Field compression is typically used to allow a gathering system to operate at a lower pressure or provide sufficient pressure to deliver gas into a higher downstream pipeline. If field compression is not installed, then the remaining natural gas in the ground will not be produced because it cannot overcome the higher gathering system pressure. In contrast, if field compression is installed, then a well can continue delivering natural gas that otherwise would not be produced.

Natural gas dehydration. Produced natural gas is saturated with water, which must be removed because the combination of natural gas and water can form ice that can plug various parts of the pipeline gathering and transportation system. Water in a natural gas stream can also cause corrosion when combined with carbon dioxide or hydrogen sulfide in natural gas. In addition, condensed water in the pipeline can raise pipeline pressure. To avoid these potential issues and to meet downstream pipeline and end-user gas quality standards, natural gas is dehydrated to remove the saturated water.

Natural gas treating. Natural gas has a varied composition depending on the field, the formation and the reservoir from which it is produced. Natural gas from certain formations can be high in carbon dioxide or hydrogen sulfide. Natural gas with high carbon dioxide or hydrogen sulfide levels may cause significant damage to pipelines and is generally not acceptable to end-users. To alleviate the potential adverse effects of these contaminants, many pipelines regularly inject corrosion inhibitors into the gas stream.

We own three treating facilities, including an amine treating facility and two hydrogen sulfide scavenger facilities. The amine treating process involves a continuous circulation of a liquid chemical called amine that physically contacts with the natural gas. Amine has a chemical affinity for hydrogen sulfide and carbon dioxide that allows it to absorb the impurities from the gas. After mixing, gas and amine are separated and the impurities are removed from the amine by heating. The treating plants are sized by the amine circulation capacity in terms of gallons per minute. The hydrogen sulfide scavenger facilities use a liquid or solid chemical that reacts with hydrogen sulfide thereby removing it from the natural gas.

Natural gas processing. Natural gas processing involves the separation of natural gas into pipeline quality natural gas and a mixed NGL stream. The principal components of natural gas are methane and ethane, but most natural gas also contains varying amounts of other NGLs. Most natural gas produced by a well is not suitable for long-haul pipeline transportation or commercial use and must be processed to remove the heavier hydrocarbon components. Natural gas is processed not only to remove unwanted NGLs that would interfere with pipeline transportation or use of the natural gas, but also to separate from the gas those hydrocarbon liquids that have higher value as NGLs. The removal and separation of individual hydrocarbons by processing is possible because of differences in weight, boiling point, vapor pressure and other physical characteristics.

Fractionation. Fractionation is the process by which NGLs are further separated into individual, more valuable components. NGL fractionation facilities separate mixed NGL streams into discrete NGL products: ethane, propane, isobutane, normal butane and natural gasoline. Ethane is primarily used in the petrochemical industry to produce ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Propane is used in the production of ethylene and propylene and as a heating fuel, an engine fuel and an industrial fuel. Isobutane is used principally to enhance the octane content of motor gasoline. Normal butane is used in the production of ethylene, butadiene (a key ingredient in synthetic rubber), motor gasoline and isobutane. Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is used primarily to produce motor gasoline and petrochemicals.

Fractionation takes advantage of the differing boiling points of the various NGL products. NGLs are fractionated by heating mixed NGL streams and passing them through a series of distillation towers. As the temperature of the NGL stream is increased, the lightest (lowest boiling point) NGL product boils off the top of the tower where it is condensed and routed to storage. The mixture from the bottom of the first tower is then moved into the next tower where the process is repeated, and a different NGL product is separated and stored. This process is repeated until the NGLs have been separated into their components. Because the fractionation process uses large quantities of heat, energy costs are a major component of the total cost of fractionation.

Natural gas transportation. Natural gas transportation pipelines receive natural gas from other mainline transportation pipelines and gathering systems and deliver the processed natural gas to industrial end-users and utilities and to other pipelines. We currently do not engage in natural gas transportation.

NGL transportation. NGLs are transported to market by means of pipelines, pressurized barges, rail car and tank trucks. The method of transportation utilized depends on, among other things, the existing resources of the transporter, the locations of the production points and the delivery points, cost-efficiency and the quantity of NGLs being transported. Pipelines are generally the most cost-efficient mode of transportation when large, consistent volumes of NGLs are to be delivered. We currently do not engage in NGL transportation.

Midstream Assets

Our natural gas gathering systems include approximately 1,124 miles of pipeline. A substantial majority of our revenues are derived from gathering, compressing, dehydrating, treating, processing and marketing the natural gas that flows through our gathering pipelines and from fractionating NGLs resulting from the processing of natural gas into NGL products. We describe our principal systems below.

Eagle Chief Gathering System

General. The Eagle Chief gathering system is located in northwest Oklahoma and consists of approximately 554 miles of natural gas gathering pipelines, ranging from two inches to 16 inches in diameter, and the Eagle Chief processing plant. The gathering system has a capacity of approximately 30,000 Mcf/d and average throughput was approximately 20,370 Mcf/d for the nine months ended September 30, 2005. There are four gas compressor stations located within the gathering system, comprised of nine units with an aggregate of approximately 7,875 horsepower.

We completed construction and commenced operation of the Eagle Chief gathering system in 1990 and constructed the Eagle Chief processing plant in 1995. Since its construction, we have expanded the size of the Eagle Chief gathering system through the acquisition of approximately 377 miles of gathering pipelines in five separate acquisitions, including our acquisition of the Carmen gathering system, and the construction of approximately 177 miles of gathering pipelines.

The Eagle Chief processing plant processes natural gas that flows through the Eagle Chief gathering system to produce residue gas and NGLs. The natural gas gathered in this system is lean gas that is not required to be processed to meet pipeline quality specifications when we sell into interstate markets. The plant has processing capacity of approximately 25,000 Mcf/d. During the nine months ended September 30, 2005, the facility processed approximately 20,370 Mcf/d of natural gas and produced approximately 745 Bbls/d of NGLs.

Natural Gas Supply. As of September 30, 2005, 368 wells were connected to our Eagle Chief gathering system. These wells are located in the Anadarko Basin of northwestern Oklahoma and generally have long lives with predictable steady flow rates. The primary suppliers of natural gas to the Eagle Chief gathering system are Chesapeake Operating and Continental Resources, which represented approximately 64.6% and 12.7%, respectively, of the Eagle Chief gathering system's natural gas supply for the nine months ended September 30, 2005.

The natural gas supplied to the Eagle Chief gathering system is generally dedicated to us under individually negotiated long-term contracts. Some of our contracts have an initial term of five years.

Following the initial term, these contracts generally continue on a year to year basis unless terminated by one of the producers. In addition, some of our contracts are for the life of the lease. Natural gas is purchased at the wellhead from the producers under percentage-of-proceeds contracts, percent-of-index contracts or fee-based contracts. For the nine months ended September 30, 2005, approximately 45.9%, 48.9% and 5.2% of our pro forma total segment margin attributable to the Eagle Chief gathering system was derived from percentage-of-proceeds, percent-of-index and fee-based contracts, respectively. For a more complete discussion of our natural gas purchase contracts, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations Our Contracts Our Natural Gas Purchase Contracts."

Our Eagle Chief gathering system is located in an active drilling area. Recently, this area has experienced increased levels of natural gas exploration, development and production activities as a result of recent high natural gas prices, new discoveries and the implementation of new exploration and production techniques. For example, our average throughput at the Eagle Chief gathering system increased from 16,900 Mcf/d for December 2003 to 22,100 Mcf/d for September 2005. In addition, during the nine months ended September 30, 2005, we added 21 wells to our system. We believe that this higher level of exploration and development activity in this area will continue and that many of the producers drilling in the area will choose to use our midstream natural gas services due to our excess capacity in this system and limited competitive alternatives.

Markets for Sale of Natural Gas and NGLs. The Eagle Chief gathering system has numerous market outlets for the natural gas that we gather and NGLs that we produce on the system. The residue gas is sold at the tailgate of the Eagle Chief processing plant on the Oklahoma Gas Transportation pipeline to intrastate markets and on the Panhandle Eastern Pipeline Company pipeline to interstate markets. Because the area connected to our Eagle Chief gathering system produces lean natural gas, we are able to bypass our Eagle Chief processing plant by selling into the interstate markets when processing margins are unfavorable. The NGLs extracted from the gas at the Eagle Chief processing plant are transported by pipeline to ONEOK Hydrocarbon Company's Medford facility for fractionation. We are currently selling the NGLs to ONEOK Hydrocarbon under a year to year contract.

Our primary purchasers of residue gas and NGLs on the Eagle Chief gathering system are BP Energy Company, OGE Energy Resources, Inc. and ONEOK Hydrocarbon, which represented approximately 30.4%, 23.1% and 18.9%, respectively, of the revenues from such sales for the nine months ended September 30, 2005.

Bakken Gathering System

General. The Bakken gathering system is located in eastern Montana and consists of approximately 256 miles of natural gas gathering pipelines, ranging from three inches to 12 inches in diameter, the Bakken processing plant and a fractionation facility. The gathering system has a capacity of approximately 25,000 Mcf/d and average throughput was approximately 8,260 Mcf/d for the nine months ended September 30, 2005. There are two gas compressor stations located within the gathering system, comprised of three units with an aggregate of approximately 4,434 horsepower.

We acquired the Bakken gathering system in September 2005 in connection with our acquisition of Hiland Partners, LLC. The Bakken gathering system, including the Bakken processing plant, was constructed during 2004 and commenced operations on November 8, 2004.

The Bakken processing plant processes natural gas that flows through the Bakken gathering system to produce residue gas and NGLs. The plant has processing capacity of approximately 25,000 Mcf/d. During the nine months ended September 30, 2005, the facility processed approximately 8,260 Mcf/d of natural gas and produced approximately 1,008 Bbls/d of NGLs.

The Bakken gathering system also includes a fractionation facility that separates NGLs into propane and a mixture of butane and gasoline. The fractionation facility has a capacity to fractionate approximately 4,600 Bbls/d of NGLs. For the nine months ended September 30, 2005, the facility fractionated an average of approximately 1,582 Bbls/d to produce approximately 535 Bbls/d of propane and approximately 459 Bbls/d of a mixture of butane and gasoline.

Natural Gas Supply. As of September 30, 2005, 131 wells were connected to our Bakken gathering system. These wells, which are located in the Williston Basin of Montana, primarily produce crude oil from the Bakken formation. The associated natural gas produced from these wells flows through our Bakken gathering system. The primary suppliers of natural gas to the Bakken gathering system are Lyco Energy Corporation, Continental Resources and Burlington Resources Trading, Inc., which represented approximately 51.6%, 38.2% and 9.2%, respectively, of the Bakken gathering system's natural gas supply for the nine months ended September 30, 2005.

Substantially all of the natural gas supplied to the Bakken gathering system is dedicated to us under three individually negotiated percentage-of-proceeds contracts. Two of these contracts have an initial term of ten years and one is for the life of the lease. Under these contracts, natural gas is purchased at the wellhead from the producers. For a more complete discussion of our natural gas purchase contracts, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations Our Contracts Our Natural Gas Purchase Contracts."

Our Bakken gathering system is located in an active drilling area. For example, during the nine months ended September 30, 2005, we added 94 wells to our system. We believe that this higher level of exploration and development activity in this area will continue and that many of the producers drilling in the area will choose to use our midstream natural gas services due to our excess capacity in this system and limited competitive alternatives.

Markets for Sale of Natural Gas and NGLs. Residue gas derived from our processing operations is sold at the tailgate of the Bakken processing plant on the Williston Basin Intrastate Pipeline to intrastate markets. We sell the propane that is produced by our fractionation facility and the remaining NGL products to various end-users at the tailgate of the plant.

Our primary purchasers of residue gas and NGLs on the Bakken gathering system are SemStream, L.P., Tenaska Marketing Ventures and Montana-Dakota Utilities Company, which represented approximately 43.8%, 29.0% and 23.6%, respectively, of the revenues from such sales for the nine months ended September 30, 2005.

Worland Gathering System

General. The Worland gathering system is located in central Wyoming and consists of approximately 151 miles of natural gas gathering pipelines, ranging from two inches to eight inches in diameter, the Worland processing plant, a natural gas treating facility and a fractionation facility. The gathering system has a capacity of approximately 8,000 Mcf/d and average throughput was approximately 3,110 Mcf/d for the nine months ended September 30, 2005. There are four gas compressor stations located within the gathering system, comprised of six units with an aggregate of approximately 2,200 horsepower.

We acquired the Worland gathering system, including the Worland processing plant, in 2000. This system, including the Worland processing plant, was originally built in the mid 1980s. A substantial portion of the equipment on the Worland gathering system, including the Worland processing plant, the treating facility and the fractionation facility, was replaced in 1997.

The Worland processing plant processes natural gas that flows through the Worland gathering system to produce residue gas and NGLs. The natural gas gathered in this system is rich gas that must be processed in order to meet pipeline quality specifications. The plant has processing capacity of approximately 8,000 Mcf/d. During the nine months ended September 30, 2005, the facility processed approximately 3,110 Mcf/d of natural gas and produced approximately 160 Bbls/d of NGLs.

The Worland gathering system includes a natural gas amine treating facility that removes carbon dioxide and hydrogen sulfide from natural gas that is gathered into our system before the natural gas is introduced to transportation pipelines to ensure that it meets pipeline quality specifications. Generally, the natural gas gathered in this system contains a high concentration of hydrogen sulfide, a highly toxic and corrosive chemical that must be removed prior to transporting the gas via pipeline. Our Worland treating facility has a circulation capacity of 70 gallons per minute and throughput capacity of 8,000 Mcf/d.

The Worland gathering system also includes a fractionation facility that separates NGLs into propane and a mixture of butane and gasoline. The fractionation facility has a capacity to fractionate approximately 650 Bbls/d of NGLs. For the nine months ended September 30, 2005, the facility fractionated an average of approximately 355 Bbls/d to produce approximately 60 Bbls/d of propane and approximately 60 Bbls/d of a mixture of butane and gasoline.

Natural Gas Supply. As of September 30, 2005, 94 wells were connected to our Worland gathering system. These wells are located in the Bighorn Basin of central Wyoming and generally have long lives with predictable and steady flow rates. The primary suppliers of natural gas to the Worland gathering system are Continental Resources and KCS Resources, Inc., which represented approximately 64.0% and 25.8%, respectively, of the Worland gathering system's natural gas supply for the nine months ended September 30, 2005.

The natural gas supplied to the Worland gathering system is generally dedicated to us under individually negotiated long-term contracts. The initial term of such agreements is generally ten years with five years remaining on most of the contracts. Following the initial term, these contracts generally continue on a year to year basis, unless terminated by one of the producers. Natural gas is purchased at the wellhead from the producers under percent-of-index contracts and fixed price contracts. For the nine months ended September 30, 2005, approximately 94.6% and 5.4% of our pro forma total segment margin attributable to the Worland gathering system was derived from percent-of-index contracts and fixed priced contracts, respectively. For a more complete discussion of our natural gas purchase contracts, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations Our Contracts Our Natural Gas Purchase Contracts."

Markets for Sale of Natural Gas and NGLs. Residue gas derived from our processing operations is sold at the tailgate of the Worland processing plant on the Williston Basin Intrastate Pipeline to intrastate markets. We sell the propane that is produced by our fractionation facility and the remaining NGL products to various end-users at the tailgate of the plant.

Our primary purchasers of residue gas and NGLs on the Worland gathering system are Rainbow Gas Company and a subsidiary of Kinder Morgan Energy Partners, L.P., which represented approximately 60.1% and 23.1%, respectively, of revenues from such sales on the Worland gathering system for the nine months ended September 30, 2005.

Badlands Gathering System and Air Compression and Water Injection Facilities

General. The Badlands gathering system is located in southwestern North Dakota and consists of approximately 108 miles of natural gas gathering pipelines, ranging from two inches to eight inches in diameter, the Badlands processing plant, a natural gas treating facility and a fractionation facility. The gathering system has a capacity of approximately 5,000 Mcf/d and average throughput was approximately 3,080 Mcf/d for the nine months ended September 30, 2005. There are four gas compressor stations located within the gathering system, comprised of four units with an aggregate of approximately 1,128 horsepower.

We completed construction and commenced operation of the Badlands gathering system, including the Badlands processing plant, in 1997. The Badlands processing plant processes natural gas that flows through the Badlands gathering system to produce residue gas and NGLs. The natural gas gathered in this system is rich gas that must be processed in order to meet pipelines quality specifications. The plant has processing capacity of approximately 5,000 Mcf/d. During the nine months ended September 30, 2005, the facility processed approximately 3,080 Mcf/d of natural gas and produced approximately 342 Bbls/d of NGLs.

The Badlands gathering system includes a natural gas treating facility that uses a solid chemical to remove hydrogen sulfide from natural gas that is gathered into our system before the natural gas is introduced to transportation pipelines to ensure it meets pipeline quality specifications. Our Badlands treating facility has throughput capacity of 7,100 Mcf/d.

The Badlands gathering system also includes a fractionation facility that separates NGLs into propane and a mixture of butane and gasoline. The fractionation facility has a capacity to fractionate approximately 600 Bbls/d of NGLs. For the nine months ended September 30, 2005, the facility fractionated an average of approximately 375 Bbls/d of to produce approximately 108 Bbls/d of propane and approximately 149 Bbls/d of a mixture of butane and gasoline.

On November 8, 2005, we entered into a new 15-year definitive gas purchase agreement with Continental Resources, Inc. under which we will gather, treat and process additional natural gas, which is produced as a by-product of Continental Resources' secondary oil recovery operations, in the areas specified by the contract. In order to fulfill our obligations under the agreement, we intend to expand our Badlands gas gathering system and processing plant located in Bowman County, North Dakota. This expansion project will include the construction of a 40,000 Mcf/d nitrogen rejection plant and the expansion of our existing Badlands field gathering infrastructure. The expansion project, which is targeted for completion in the 4th quarter of 2006, is expected to cost approximately $40 million, which we intend to fund using our existing bank credit facility. Moreover, we expect to spend an additional $9.5 million in 2007 to expand the system.

Natural Gas Supply. As of September 30, 2005, 96 wells were connected to our Badlands gathering system. These wells are located in the Williston Basin of southwestern North Dakota and generally have long lives with predictable and steady flow rates. The primary suppliers of natural gas to the Badlands gathering system are Continental Resources, Luff Exploration Company and Burlington Resources, which represented approximately 59.1%, 18.1% and 13.8%, respectively, of the Badlands gathering system's natural gas supply for the nine months ended September 30, 2005.

The natural gas supplied to the Badlands gathering system is generally dedicated to us under individually negotiated long-term contracts. Our new agreement with Continental Resources has an initial term of 15 years. Under this agreement, we will receive 50% of the proceeds attributable to residue gas and natural gas liquids sales as well as certain fixed fees associated with gathering and treating the natural gas, including a $0.60 per Mcf fee for the first 36 Bcf of natural gas gathered. This agreement will replace our existing agreement with Continental Resources in the area when the new plant becomes operational. The initial term of our other agreements in this area is generally ten years with five years remaining on most of the contracts. Following the initial term, these contracts generally continue on a year to year basis, unless terminated by one of the producers. For these other agreements, natural gas is purchased at the wellhead from the producers under percentage-of-index arrangements. For a more complete discussion of our natural gas purchase contracts, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations Our Contracts Our Natural Gas Purchase Contracts."

Air Compression and Water Injection Facilities. We believe that our Badlands gathering system is strategically located in an area where secondary recovery operations may provide us with additional natural gas supplies. In order to enhance the production of natural gas that flows through out Badlands gathering system, we currently provide air compression and water injection services to Continental Resources under long-term contracts at our Cedar Hills compression facility, our Horse Creek compression facility and our water injection Plant, all of which are located in North Dakota in close proximity to our Badlands gathering system. For a description of these services, please read " Compression Assets."

Markets for Sale of Natural Gas and NGLs. Residue gas derived from our processing operations is sold at the tailgate of the Badlands processing plant to end-users or on an interstate pipeline located at the tailgate of the plant. We sell the propane that is produced by our fractionation facility and the remaining NGL products to various end-users at the tailgate of the plant.

Our primary purchasers of the residue gas, propane and NGLs from the Badlands gathering system are Continental Resources, a subsidiary of Kinder Morgan Energy Partners, L.P. and a subsidiary of Plains All American Pipeline, L.P., which represented approximately 35.7%, 25.3% and 20.2%, respectively, of the revenues from such sales for the nine months ended September 30, 2005.

Matli Gathering System

General. The Matli Gathering System is located in central Oklahoma and consists of approximately 37 miles of natural gas gathering pipelines, ranging from three inches to 12 inches in diameter, the Matli processing plant and a natural gas treating facility. The gathering system has a capacity of approximately 20,000 Mcf/d and average throughput was approximately 14,640 Mcf/d for the nine months ended September 30, 2005. There are two gas compressor stations located within the gathering system, comprised of six units with an aggregate of approximately 5,746 horsepower.

We completed construction and commenced operation of the Matli gathering system in 1999 and constructed the Matli processing plant in 2003. The Matli processing plant processes natural gas on the Matli gathering system to produce residue gas and NGLs. The natural gas gathered in this system must be processed in order to meet pipeline quality specifications, but is relatively lean gas. The plant has processing capacity of approximately 10,000 Mcf/d. During the nine months ended September 30, 2005, the facility processed approximately 5,010 Mcf/d of natural gas and produced approximately 148 Bbls/d of NGLs.

The Matli gathering system includes a natural gas treating facility that uses a liquid chemical to remove hydrogen sulfide from natural gas that is gathered into our system before the natural gas is introduced to transportation pipelines to ensure it meets pipeline quality specifications. Our Matli treating facility has throughput capacity of 10,000 Mcf/d. During the nine months ended September 30, 2005, the facility treated approximately 9,510 Mcf/d of natural gas.

Natural Gas Supply. As of September 30, 2005, 38 wells were connected to our Matli gathering system. These wells are located in the Anadarko Basin of central Oklahoma and generally have long lives with predictable and steady flow rates. The primary suppliers of natural gas to the Matli gathering system are Continental Resources and Range Resources Corporation, which represented approximately 49.2% and 40.3%, respectively, of the Matli gathering system's natural gas supply for the nine months ended September 30, 2005.

The Matli gathering system is located in an active drilling area. The natural gas supplied to the Matli gathering system is generally dedicated to us under individually negotiated long-term contracts. The initial term of such agreements is generally ten years with five years remaining on most of the contracts. Following the initial term, these contracts generally continue on a year to year basis, unless terminated by one of the producers. Natural gas is purchased at the wellhead from the producers under fee-based contracts. For a more complete discussion of our natural gas purchase contracts, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations Our Contracts Our Natural Gas Purchase Contracts."

Markets for Sale of Natural Gas and NGLs. Residue gas resulting from our processing operations is sold at the tailgate of the plant on the Oklahoma Gas Transportation intrastate pipeline. The NGLs produced at the Matli processing plant are transported by truck to the ONEOK Hydrocarbon Medford facility for fractionation.

Our primary purchasers of residue gas and NGLs on the Matli gathering system are BP Energy, OGE Energy Resources and Tenaska Marketing Ventures, which represented approximately 18.6%, 51.1% and 16.8%, respectively, of the revenues from such sales for the nine months ended September 30, 2005.

Other Systems

In addition to the midstream assets described above, we own two gathering systems located in Texas and Mississippi and a gathering pipeline system in Oklahoma. These assets do not provide us with material cash flows and consist of the following:

Driscoll Gathering System. Our Driscoll gathering system is located in south Texas and consists of approximately four miles of natural gas gathering pipeline and a compressor station.

Stovall Gathering System. Our Stovall gathering system is located in northern Mississippi and consists of approximately nine miles of natural gas gathering pipeline and a compressor station.

Enid Pipeline System. Our Enid pipeline system is located in northern Oklahoma and consists of approximately five miles of pipeline.

Compression Assets

We completed construction of our Cedar Hills compression facility and acquired the Horse Creek compression facility in 2002. The Cedar Hills compression facility is comprised of six units with an aggregate of approximately 24,000 horsepower. The Horse Creek compression facility is comprised of three units with an aggregate of approximately 900 horsepower.

At the compression facilities, we compress air to pressures in excess of 4,000 pounds per square inch. At our water injection plant, water is produced from source wells located near the water plant site. Produced water is run through a filter system to remove impurities and is then cooled prior to being pumped to pressures in excess of 2,000 pounds per square inch. The air and water are delivered at the tailgate of our facilities into pipelines owned by Continental Resources and are ultimately utilized by Continental Resources in its oil and gas secondary recovery operations. For a description of the services agreement we entered into with Continental Resources in connection with our initial public offering, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations Our Contracts Compression Services Agreement."

Competition

The natural gas gathering, treating, processing and marketing industries are highly competitive. We face strong competition in acquiring new natural gas supplies. Our competitors include other natural gas gatherers that gather, process and market natural gas. Competition for natural gas supplies is primarily based on the reputation, efficiency, flexibility and reliability of the gatherer, the pricing arrangements offered by the gatherer and the location of the gatherer's pipeline facilities; a competitive advantage for us because of our proximity to established and new production. We provide flexible services to natural gas producers, including natural gas gathering, compression, dehydrating, treating and processing. We believe our ability to furnish these services gives us an advantage in competing for new supplies of natural gas because we can provide the services that producers, marketers and others require to connect their natural gas quickly and efficiently. In addition, using centralized treating and processing facilities, we can in most cases attract producers that require these services more quickly and at a lower initial capital cost due in part to the elimination of some field equipment. For natural gas that exceeds the maximum carbon dioxide and NGL specifications for interconnecting pipelines and downstream markets, we believe that we offer treating and other processing services on competitive terms. In addition, with respect to natural gas customers attached to our pipeline systems, we provide natural gas supplies on a flexible basis.

We believe that our producers prefer a midstream energy company with the flexibility to accept natural gas not meeting typical industry standard gas quality requirements. The primary difference between us and our competitors is that we provide an integrated and responsive package of midstream services, while most of our competitors typically offer only a few select services. We believe that offering an integrated package of services, while remaining flexible in the types of contractual arrangements that we offer producers, allows us to compete more effectively for new natural gas supplies.

Many of our competitors have capital resources and control supplies of natural gas greater than ours. Our primary competitors on the Eagle Chief gathering system are Western Gas Resources, Inc., Ringwood Gathering, and Duke Energy Field Services. Our primary competitor on the Bakken gathering system and the Badlands gathering system is Bear Paw Energy, and on the Matli gathering system is Enogex Inc. We do not have a major competitor on the Worland gathering system.

Regulation

Regulation by the FERC of Interstate Natural Gas Pipelines. We do not own any interstate natural gas pipelines, so the Federal Energy Regulatory Commission, or the FERC, does not directly regulate any of our operations. However, the FERC's regulation influences certain aspects of our business and the market for our products. In general, the FERC has authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce, and its authority to regulate those services includes:

- the certification and construction of new facilities;
- the extension or abandonment of services and facilities;
- the maintenance of accounts and records;
- the acquisition and disposition of facilities;
- the initiation and discontinuation of services; and
- various other matters.

In recent years, the FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, we cannot assure you that the FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity.

Intrastate Regulation of Natural Gas Transportation Pipelines. We do not own any pipelines that provide intrastate natural gas transportation, so state regulation of pipeline transportation does not directly affect our operations. As with FERC regulation described above, however, state regulation of pipeline transportation may influence certain aspects of our business and the market for our products.

Gathering Pipeline Regulation. Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of the FERC. We own a number of intrastate natural gas pipelines that we believe would meet the traditional tests the FERC has used to establish a pipeline's status as a gatherer not subject to the FERC jurisdiction, were it determined that those intrastate lines should be classified as interstate lines. However, the distinction between the FERC-regulated transmission services and federally unregulated gathering services is the subject of regular litigation, so, in such a circumstance,

the classification and regulation of some of our gathering facilities may be subject to change based on future determinations by the FERC and the courts.

In the states in which we operate, regulation of intrastate gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirement and complaint based rate regulation. For example, we are subject to state ratable take and common purchaser statutes. Ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. In certain circumstances, such laws will apply even to gatherers like us that do not provide third party, fee-based gathering service and may require us to provide such third party service at a regulated rate. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas.

Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels now that the FERC has taken a less stringent approach to regulation of the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. Our gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Sales of Natural Gas. The price at which we buy and sell natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. Our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. The FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to the FERC's jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry, and these initiatives generally reflect more light handed regulation. We cannot predict the ultimate impact of these regulatory changes to our natural gas marketing operations, and we note that some of the FERC's more recent proposals may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any such FERC action materially differently than other natural gas marketers with whom we compete.

Environmental Matters

The operation of pipelines, plants and other facilities for gathering, compressing, dehydrating, treating, or processing of natural gas, NGLs and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

- restricting the way we can handle or dispose of our wastes;

- limiting or prohibiting construction activities in sensitive areas such as wetlands, coastal regions, or areas inhabited by endangered species;
- requiring remedial action to mitigate pollution conditions caused by our operations, or attributable to former operations; and
- enjoining the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of substances or other waste products into the environment.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. We try to anticipate future regulatory requirements that might be imposed and plan accordingly to remain in compliance with changing environmental laws and regulations and to minimize the costs of such compliance. We also actively participate in industry groups that help formulate recommendations for addressing existing or future regulations.

We do not believe that compliance with federal, state or local environmental laws and regulations will have a material adverse effect on our business, financial position or results of operations. In addition, we believe that the various environmental activities in which we are presently engaged are not expected to materially interrupt or diminish our operational ability to gather, compress, treat, fractionate and process natural gas. We cannot assure you, however, that future events, such as changes in existing laws, the promulgation of new laws, or the development or discovery of new facts or conditions will not cause us to incur significant costs. The following is a discussion of the material environmental and safety laws and regulations that can apply to our operations. We believe that we are in substantial compliance with these environmental laws and regulations.

Air Emissions. Our operations are subject to the federal Clean Air Act and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our processing and treatment plants, fractionation facilities and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations, or utilize specific emission control technologies to limit emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. We will be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe, however, that our operations will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to us than to other similarly situated companies.

Hazardous Waste. Our operations generate wastes, including some hazardous wastes, that are subject to the federal Resource Conservation and Recovery Act, or RCRA, and comparable state laws, which impose detailed requirements for the handling, storage, treatment and disposal of hazardous and solid waste. RCRA currently exempts many natural gas gathering and field processing wastes from classification as hazardous waste. Specifically, RCRA excludes from the definition of hazardous waste produced waters and other wastes associated with the exploration, development, or production of crude oil and natural gas. However, these oil and gas exploration and production wastes may still be regulated under state law or the less stringent solid waste requirements of RCRA. Moreover, ordinary industrial wastes such as paint wastes, waste solvents, laboratory wastes, and waste compressor oils may be regulated as hazardous waste. The transportation of natural gas in pipelines may also generate some hazardous wastes that are subject to RCRA or comparable state law requirements.

Site Remediation. The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended, or CERCLA, also known as "Superfund," and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons responsible for the release of hazardous substances into the environment. Such classes of persons include the current and past owners or operators of sites where a hazardous substance was released, and companies that disposed or arranged for disposal of hazardous substances at offsite locations such as landfills. Although petroleum as well as natural gas is excluded from CERCLA's definition of "hazardous substance," in the course of our ordinary operations we will generate wastes that may fall within the definition of a "hazardous substance." CERCLA authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. Under CERCLA, we could be subject to joint and several liability for the costs of cleaning up and restoring sites where hazardous substances have been released, for damages to natural resources, and for the costs of certain health studies.

Water Discharges. Our operations are subject to the Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act, and analogous state laws and regulations. These laws and regulations impose detailed requirements and strict controls regarding the discharge of pollutants into waters of the United States. The unpermitted discharge of pollutants, including discharges resulting from a spill or leak incident, is prohibited. The Clean Water Act and regulations implemented thereunder also prohibit discharges of dredged and fill material into wetlands and other waters of the United States unless authorized by an appropriately issued permit. Any unpermitted release of pollutants from our pipelines or facilities could result in fines or penalties as well as significant remedial obligations.

Pipeline Safety. Our pipelines are subject to regulation by the U.S. Department of Transportation, or the DOT, under the Natural Gas Pipeline Safety Act of 1968, as amended, or the NGPSA, pursuant to which the DOT has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. The NGPSA covers the pipeline transportation of natural gas and other gases, and the transportation and storage of liquefied natural gas (LNG) and requires any entity that owns or operates pipeline facilities to comply with the regulations under the NGPSA, to permit access to and allow copying of records and to make certain reports and provide information as required by the Secretary of Transportation. We believe that our pipeline operations are in substantial compliance with applicable NGPSA requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, future compliance with the NGPSA could result in increased costs that, at this time, cannot reasonably be quantified.

The DOT, through the Office of Pipeline Safety, recently adopted regulations to implement the Pipeline Safety Improvement Act, which requires pipeline operators to, among other things, develop integrity management programs for gas transmission pipelines that, in the event of a failure, could affect "high consequence areas." "High consequence areas" are currently defined as areas with specified population densities, buildings containing populations of limited mobility, and areas where people gather that are located along the route of a pipeline. States in which we operate have adopted similar regulations applicable to intrastate gathering and transmission lines. Compliance with these regulations could result in increased operating costs that, at this time, cannot reasonably be quantified.

Employee Health and Safety. We are subject to the requirements of the Occupational Safety and Health Act, referred to as OSHA, and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens.

Hydrogen Sulfide. Exposure to gas containing high levels of hydrogen sulfide, referred to as sour gas, is harmful to humans, and prolonged exposure can result in death. The gas handled at our Worland gathering system contains high levels of hydrogen sulfide, and we employ numerous safety precautions at the system to ensure the safety of our employees. There are various federal and state environmental and safety requirements for handling sour gas, and we are in compliance with all such requirements.

Title to Properties

Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of the property. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the right-of-way grants. We have obtained, where necessary, license or permit agreements from public authorities and railroad companies to cross over or under, or to lay facilities in or along, waterways, county roads, municipal streets, railroad properties and state highways, as applicable. In some cases, property on which our pipelines were built was purchased in fee.

Some of our leases, easements, rights-of-way, permits, licenses and franchise ordinances require the consent of the current landowner to transfer these rights, which in some instances is a governmental entity. We believe that we have obtained or will obtain sufficient third party consents, permits and authorizations for the transfer of the assets necessary for us to operate our business in all material respects as described in this prospectus. With respect to any consents, permits or authorizations that have not been obtained, we believe that these consents, permits or authorizations will be obtained after the closing of this offering, or that the failure to obtain these consents, permits or authorizations will have no material adverse effect on the operation of our business.

We lease the majority of the surface land on which our gathering systems operate. With respect to our Eagle Chief gathering system, we lease the surface land on which the Eagle Chief processing plant, three of the four compressor stations, a dumping station and the three pumping stations are located. With respect to our Bakken gathering system, we own the land on which the processing plant is located and the land on which the compressor stations are located. In our Worland gathering system, we lease the surface land on which the Worland processing plant and the compressor stations are located. With respect to our Badlands gathering system, we own the land on which the Badlands processing plant is located and we lease the land on which the four compressor sites are located. In addition, we lease the surface lands on which our Matli processing plant and compressor station are located.

We believe that we have satisfactory title to all of our assets. Record title to some of our assets may continue to be held by our affiliates until we have made the appropriate filings in the jurisdictions in which such assets are located and obtained any consents and approvals that are not obtained prior to transfer. Title to property may be subject to encumbrances. We believe that none of these encumbrances will materially detract from the value of our properties or from our interest in these properties nor will they materially interfere with their use in the operation of our business.

We believe that we either own in fee or have leases, easements, rights-of-way or licenses and have obtained the necessary consents, permits and franchise ordinances to conduct our operations in all material respects.

Office Facilities

In addition to our pipelines and processing facility discussed above, we occupy approximately 6,387 square feet of space at our executive offices in Enid, Oklahoma, under a lease expiring on August 31, 2009. While we may require additional office space as our business expands, we believe that our existing facilities are adequate to meet our needs for the immediate future and that additional facilities will be available on commercially reasonable terms as needed.

Employees

As of September 30, 2005, we had approximately 66 full-time employees. We are not a party to any collective bargaining agreements and we have not had any significant labor disputes in the past. We believe we have good relations with our employees. All of our employees are employees of our general partner. In addition, certain of our general partner's employees provide services to Continental Resources in connection with the operation of compression assets owned by Continental Resources.

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. We maintain insurance policies with insurers in amounts and with coverage and deductibles as our general partner believes are reasonable and prudent. However, we cannot assure you that this insurance will be adequate to protect us from all material expenses related to potential future claims for personal and property damage or that these levels of insurance will be available in the future at economical prices.

MANAGEMENT

Management of Hiland Partners, LP

Hiland Partners GP, LLC, as our general partner, manages our operations and activities on our behalf. Our general partner is not elected by our unitholders and will not be subject to re-election on a regular basis in the future. Unitholders will not be entitled to elect the directors of Hiland Partners GP, LLC or 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 expressly nonrecourse to it. Whenever possible, our general partner intends to cause us to incur indebtedness or other obligations that are nonrecourse to it.

Two 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 determines 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 the NASDAQ National Market and the SEC to serve on an audit committee of a board of directors. 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. The chairman of the conflicts committee is Michael L. Greenwood and Edward D. Doherty serves as a member of the conflicts committee.

In addition, we have an audit committee of two independent directors that 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. In compliance with the rules of the NASDAQ National Market, the members of the board of directors named below will appoint one additional independent member to the audit committee within twelve months of our initial public offering. The chairman of the audit committee is Michael L. Greenwood and Edward D. Doherty serves as a member on the audit committee. We also have a compensation committee of four directors which oversee compensation decisions for the officers of our general partner as well as the compensation plans described below. The chairman of the compensation committee is Edward D. Doherty and Michael L. Greenwood, Harold Hamm and Rayford T. Reid serve as members of the compensation committee.

Our operational personnel are employees of our general partner or its affiliates. The officers of our general partner spend substantially all of their time managing our business and affairs.

Directors and Executive Officers of Hiland Partners GP, LLC

The following table shows information regarding the current directors and executive officers of Hiland Partners GP, LLC. Directors are elected for one-year terms.

Name	Age	Position with Hiland Partners GP, LLC
Harold Hamm	59	Chairman of the Board of Directors
Randy Moeder	45	Chief Executive Officer, President and Director
Ken Maples	43	Chief Financial Officer, Vice President Finance, Secretary and Director
Clint Duty	45	Vice President Operations and Engineering
Michael L. Greenwood	50	Director
Edward D. Doherty	70	Director
Rayford T. Reid	57	Director
Shelby E. Odell	66	Director

Harold Hamm was elected Chairman of the Board of Directors of our general partner in October 2004 and serves as a member of the compensation committee of the board of directors of our general partner. Mr. Hamm has served as President and Chief Executive Officer and as a director of Continental Gas, Inc. since December 1994 and then served as Chief Executive Officer and a director to 2004. Since its inception in 1967 until October 2005, Mr. Hamm served as President and Chief Executive Officer and a director of Continental Resources, Inc. and currently serves as its Chief Executive Officer and Chairman of its board of directors. Mr. Hamm is also President of the National Stripper Well Association, President and Chairman of the executive board of the Oklahoma Independent Petroleum Association and a member of the executive board of the Oklahoma Energy Explorers. In addition, Mr. Hamm is the founder and serves as Chairman of the board of directors of Save Domestic Oil, Inc. and is a director of Complete Production Services, Inc.

Randy Moeder was elected Chief Executive Officer, President and a director of our general partner in October 2004. Mr. Moeder has been Manager of Hiland Partners, LLC since its inception in October 2000. He also has been President of Continental Gas, Inc. since January 1995 and was Vice President from November 1990 to January 1995. Mr. Moeder was Senior Vice President and General Counsel of Continental Resources, Inc. from May 1998 to August 2000 and was Vice President and General Counsel from November 1990 to April 1998. From January 1988 to summer 1990, Mr. Moeder worked in private law practice. From 1982 to 1988, Mr. Moeder held various positions with Amoco Corporation. Mr. Moeder is a member of the Oklahoma Independent Petroleum Association and the Oklahoma and American Bar Associations. Mr. Moeder holds a Bachelor of Science degree in accounting from Kansas State University and a doctorate of jurisprudence from the University of Tulsa. Mr. Moeder is also a Certified Public Accountant.

Ken Maples was elected Chief Financial Officer, Vice President Finance, Secretary and a director of our general partner in October 2004. Mr. Maples has served as Chief Financial Officer of Continental Gas, Inc. and Hiland Partners, LLC since February 2004. Mr. Maples was Director of Business Development and Manager of Investor Relations of Continental Resources, Inc. from October 2002 to February 2004. From October 1990 to October 2002, Mr. Maples held various positions with Callon Petroleum Company. He holds a Bachelor degree in accounting from Mississippi State University and an MBA from Louisiana State University.

Clint Duty was elected as Vice President Operations and Engineering of our general partner in November 2004. Although new to Continental Gas, Inc. and Hiland Partners, LLC, Mr. Duty has extensive experience in operations and engineering management of natural gas gathering, treating, processing and fractionation facilities. From November 2003 until October 2004, Mr. Duty served as Director of Engineering and Construction for Red Cedar Gathering Company in Durango, Colorado. Mr. Duty was recalled to active duty military service (Navy) from December 2002 until October 2003 in support of Operation Iraqi Freedom. Prior to that, from January 2000 until December 2002, Mr. Duty held several managerial positions at CMS Field Services in Tulsa, Oklahoma. From February 1996 until December 1999, Mr. Duty worked for Koch Hydrocarbon Company as Engineering Manager at its Medford, Oklahoma and Mont Belvieu, Texas liquid hydrocarbon complexes. He holds a Bachelor of Science degree in Chemical Engineering from the University of Washington.

Michael L. Greenwood was elected as a director of our general partner in February 2005, and serves as Chairman of the audit committee and conflicts committee and as a member of the compensation committee of the board of directors of our general partner. Mr. Greenwood is founder and managing director of Carnegie Capital LLC, a financial advisory services firm providing investment banking assistance to the energy industry. Mr. Greenwood previously served as Vice President Finance and Treasurer of Energy Transfer Partners, L.P. until August 2004. Prior to its merger with Energy Transfer, Mr. Greenwood served as Vice President and Chief Financial Officer & Treasurer of Heritage Propane Partners, L.P. from 2002 to 2003. Prior to joining Heritage Propane, Mr. Greenwood was Senior Vice President, Chief Financial Officer and Treasurer for Alliance Resource Partners, L.P. from 1994 to

2002. Mr. Greenwood has over 20 years of diverse financial and management experience in the energy industry during his career with several major public energy companies including MAPCO Inc., Penn Central Corporation, and The Williams Companies. Mr. Greenwood also serves as a director of Libra Natural Resources plc and Global Power Equipment Group Inc. Mr. Greenwood holds a Bachelor of Science in Business Administration degree from Oklahoma State University and a Master of Business Administration degree from the University of Tulsa.

Edward D. Doherty was elected as a director of our general partner in February 2005, and serves as Chairman of the compensation committee and as a member of the audit and conflicts committees of the board of directors of our general partner. Mr. Doherty served as the Chairman and Chief Executive Officer of Kaneb Pipe Line Company LLC, the general partner of Kaneb Pipe Line Partners L.P. since its inception in September 1989 until July 2005. Prior to joining Kaneb, Mr. Doherty was President and Chief Executive Officer of two private companies which provided restructuring services to troubled companies and was President and Chief Executive Officer of Commonwealth Oil Refining Company, Inc., a public refining and petrochemical company. Mr. Doherty holds a Bachelor of Arts degree from Lafayette College and a Doctor of Jurisprudence from Columbia University School of Law.

Rayford T. Reid was elected as a director of our general partner in May 2005, and serves as a member of the compensation committee of the board of directors of our general partner. Mr. Reid has more than 30 years of investment banking, financial advisory and commercial banking experience, including 25 years focused on the oil and gas industry. During the last 20 years, Mr. Reid has served as President of R. Reid Investments Inc., a private investment banking firm which exclusively serves companies engaged in the energy industry. Reid Investments specializes in mergers, acquisitions and divestitures and traditional and non-traditional private placements of debt and equity. Mr. Reid holds a Bachelor of Arts degree from Oklahoma State University and a Master of Business Administration degree from the Wharton School of the University of Pennsylvania.

Shelby E. Odell was elected as a director of our general partner in September 2005. Mr. Odell has 40 years experience in the petroleum business, including marketing, distribution, acquisitions, innovation of new asset opportunities, and management. From 1974 to 2000, Mr. Odell held several positions with Koch Industries. He retired in 2000 as President of Koch Hydrocarbon Company and Sr. Vice President of Koch Industries. Prior to joining Koch, Mr. Odell advanced through several positions with Phillips Petroleum Company. He is a past member of the Board of Directors of the Gas Processors Association and holds an Associate Degree in Accounting from Enid Business College.

Reimbursement of Expenses of Our General Partner

Our general partner will not receive any management fee or other compensation for its management of our partnership. Our general partner and its affiliates will be reimbursed for all expenses incurred on our behalf. These expenses include the cost of employee, officer and director compensation benefits properly allocable to our partnership and all other expenses necessary or appropriate to the conduct of our business and allocable to us. The partnership agreement provides that our general partner will determine the expenses that are allocable to us in any reasonable manner determined by our general partner in its discretion. There is no cap on the amount that may be paid or reimbursed to our general partner for compensation or expenses incurred on our behalf. Continental Resources currently provides us with certain general and administration services. For a description of these services, please read "Certain Relationships and Related Party Transactions Agreements with Harold Hamm and His Affiliates Omnibus Agreement Services." In the omnibus agreement, Continental Resources has agreed to continue to provide these services to us for two years after our initial public offering, at the lower of Continental Resources' cost to provide the services or $50,000 per year.

Executive Compensation

We and our general partner were formed in October 2004. We have not accrued any obligations with respect to management incentive or retirement benefits for our general partners' directors and officers for the 2004 fiscal year. Messrs. Moeder, Maples and Duty currently receive an annual salary of $225,000, $190,000 and $140,000, respectively. In addition, the officers and employees of our general partner and our partnership, our subsidiaries or our affiliates may participate in employee benefit plans and arrangements sponsored by our general partner or our partnership, including plans and arrangements that may be established in the future. Other than the option agreements described below, neither we nor our general partner have entered into any employment agreements with any officers of our general partner. We have not entered into any agreement with our general partner relating to the amount of compensation of our executive officers, individually or as a group. Upon completion of our initial public offering, we granted options to purchase 32,000, 20,000 and 20,000 common units to Messrs. Moeder, Maples and Duty, respectively. The options have an exercise price equal to $22.50 per share, which was the initial public offering price, and otherwise have the terms described below under Long Term Incentive Plan.

Compensation of Directors

Officers or employees of our general partner or its affiliates who also serve as directors do not receive additional compensation. Directors who are not officers or employees of our general partner receive (a) a $25,000 annual cash retainer fee, (b) $1,500 for each regularly scheduled meeting attended, (c) $750 for each special meeting attended and (d) 2,000 restricted units upon becoming a director and 1,000 restricted units on each anniversary date of becoming a director. The restricted units vest in quarterly increments on the anniversary of the grant date over a period of four years. In addition to the foregoing, each director who serves on a committee receives $1,000 for each committee meeting attended, the chairman of our audit committee receives an annual retainer of $5,000 and the chairmen of our other committees receives an annual retainer of $2,500. In addition, each non-employee director is reimbursed for his out-of-pocket expenses in connection with attending meetings of the board of directors or committees. Each director is fully indemnified by us for his actions associated with being a director to the fullest extent permitted under Delaware law.

Long-Term Incentive Plan

Our general partner has adopted the Hiland Partners, LP Long-Term Incentive Plan for employees and directors of our general partner and employees of its affiliates, who perform services for our general partner or its affiliates. The long-term incentive plan currently permits an aggregate of 680,000 common units to be issued with respect to unit options, restricted units and phantom units granted under the plan. No more than 225,000 of the 680,000 common units may be issued with respect to vested restricted or phantom units. The plan is administered by the compensation committee of our general partner's board of directors. The plan will continue in effect until the earliest of (i) the date determined by the board of directors of our general partner; (ii) the date that common units are no longer available for payment of awards under the plan; or (iii) the tenth anniversary of the plan.

Our general partner's board of directors or compensation committee may, in their discretion, terminate, suspend or discontinue the long-term incentive plan at any time with respect to any units for which a grant has not yet been made. Our general partner's board of directors or its compensation committee also has the right to alter or amend the long-term incentive plan or any part of the plan from time to time, including increasing the number of units that may be granted, subject to unitholder approval if required by the exchange upon which the common units are listed at that time. No change in any outstanding grant may be made, however, that would materially impair the rights of the participant without the consent of the participant.

Restricted Units and Phantom Units. A restricted unit is a common unit that is subject to forfeiture. Upon vesting, the grantee receives a common unit that is not subject to forfeiture. A phantom unit is a notional unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit or, in the discretion of the compensation committee, cash equivalent to the value of a common unit. The compensation committee may make grants of restricted units and phantom units under the plan to employees and directors containing such terms as the compensation committee shall determine under the plan, including the period over which restricted units and phantom units granted will vest. The committee may, in its discretion, base its determination on the grantee's period of service or upon the achievement of specified financial objectives. In addition, the restricted and phantom units will vest upon a change of control of us or our general partner, subject to additional or contrary provisions in the award agreement.

If a grantee's employment 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 or unless otherwise provided in a written employment agreement between the grantee and our general partner or its affiliates. Common units to be delivered with respect to these awards may be common units acquired by our general partner in the open market, common units already owned by our general partner, common units acquired by our general partner directly from us or any other person or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the cost incurred in acquiring common units. If we issue new common units with respect to these awards, the total number of common units outstanding will increase.

Distributions on restricted units may be subject to the same vesting requirements as the restricted units, in the compensation committee's discretion. The compensation committee, in its discretion, may also grant tandem distribution equivalent rights with respect to phantom units. These are rights that entitle the grantee to receive cash equal to the cash distributions made on the common units.

We intend for the restricted units and phantom units under the plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, plan participants will not pay any consideration for the common units they receive, and we will receive no remuneration for the units.

Unit Options. The long-term incentive plan permits the grant of options covering common units. The compensation committee may make grants under the plan to employees and directors containing such terms as the committee shall determine. Except in the case of substitute options granted to new employees or directors in connection with a merger, consolidation or acquisition, unit options may not have an exercise price that is less than the fair market value of the units on the date of grant. In addition, unit options granted will generally become exercisable over a period determined by the compensation committee and, in the compensation committee's discretion, may provide for accelerated vesting upon the achievement of specified performance objectives. The unit options will become exercisable upon a change in control of us or the operating company. Unless otherwise provided in an award agreement, unit options may be exercised only by the participant during his lifetime or by the person to whom the participant's right will pass by will or the laws of descent and distribution.

If a grantee's employment or membership on the board of directors terminates for any reason, the grantee's unvested options will be automatically forfeited unless, and to the extent, the compensation committee provides otherwise or unless otherwise provided in a written employment agreement or the option agreement between the grantee and our general partner or its affiliates. If the exercise of an option is to be settled in common units rather than cash, the general partner will acquire common units in the open market or directly from us or any other person or use common units already owned by our general partner or any combination of the foregoing. The general partner will be entitled to reimbursement by us for the difference between the cost incurred by it in acquiring these common units and the proceeds it receives from a grantee at the time of exercise. Thus, the cost of the unit options above the proceeds from grantees will be borne by us. If we issue new common units upon exercise of the unit options, the total number of common units outstanding will increase, and our general partner will pay us the proceeds it received from the grantee upon exercise of the unit option. The plan has been designed to furnish additional compensation to employees and directors and to align their economic interests with those of common unitholders.

Unit Option Grant Agreement. As of October 1, 2005, we have granted options to purchase an aggregate of approximately 166,000 common units with a weighted average exercise price of $24.53 to employees, officers and directors of our general partner. Under the unit option grant agreements, the options vest and may be exercised in one third increments on the anniversary of the grant date over a period of three years. In addition, the unit options will vest and become exercisable, subject to certain conditions, upon the occurrence of any of the following:

- the grantee becomes disabled;
- the grantee dies;
- the grantee's employment is terminated other than for cause; and
- upon a change of control of the Partnership.

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth the beneficial ownership of our units as of October 1, 2005 held by:

each person who beneficially owned 5% or more of the then outstanding units;

each member of the board of directors and our general partner;

each named executive officer of our general partner; and

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

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned	Percentage of Total Units Beneficially Owned
Harold Hamm(1)(2)	245,872	9.0%	2,400,602	58.8%	38.9%
Harold Hamm DST Trust(2)(3)	101,442	3.7%	990,440	24.3%	16.0%
Harold Hamm HJ Trust(2)(4)	67,627	2.5%	660,293	16.2%	10.7%
Randy Moeder(1)	39,149	1.4%	28,665	*	1.0%
Ken Maples(1)	13,333	*			*
Clint Duty(1)					
Michael L. Greenwood(1)	10,291(7)	*			*
Edward D. Doherty(5)	2,000(7)	*			*
Rayford T. Reid(6)	14,818(7)	*			*
Shelby E. Odell(1)	2,000(7)	*			*
All directors and executive officers as a group (8 persons)	327,463	12.0%	2,429,267	59.5%	40.5%

* Less than 1%.

(1) The address of this person is 205 West Maple, Suite 1100, Enid, Oklahoma 73701.

(2) Harold Hamm, the Harold Hamm DST Trust and the Harold Hamm HJ Trust have a 90.7%, 5.6% and 3.7% ownership interest, respectively, in Continental Gas Holdings, Inc., which, as of October 1, 2005, beneficially owned 271,082 common units and 2,646,749 subordinated units. The units held by Continental Gas Holdings, Inc. are reported in this table as beneficially owned by Mr. Hamm, the Harold Hamm DST Trust and the Harold Hamm HJ Trust in proportion to their respective ownership interest in Continental Gas Holdings, Inc. The address of Continental Gas Holdings, Inc. is 205 West Maple, Suite 1100, Enid, Oklahoma 73701.

(3) Mr. Bert Mackie is the trustee of the Harold Hamm DST Trust, and his address is c/o Security National Bank, 201 West Broadway, Enid, Oklahoma 73702-1272.

(4) Mr. Bert Mackie is the trustee of the Harold Hamm HJ Trust, and his address is c/o Security National Bank, 201 West Broadway, Enid, Oklahoma 73702-1272.

(5)
Mr. Doherty's address is 3425 N. Central Expressway, Suite 700, Richardson, Texas 75080.

(6)
Mr. Reid's address is 2435 E. Southlake, Suite 120, Southlake, Texas 76092.

(7)
2,000 of the indicated common units are restricted units that vest in quarterly increments on the anniversary of the grant date over a period of four years.

The following table shows the beneficial ownership of our general partner as of October 1, 2005 held by the Hamm Parties, the directors of our general partner, each named executive officer and by all directors and officers of our general partner as a group.

Name of Beneficial Owner	Class A Membership Interest	Class B Membership Interest
Harold Hamm(1)(2)	94.0%	55.7%
Harold Hamm DST Trust(2)		23.0%
Harold Hamm HJ Trust(2)		15.3%
Randy Moeder	4.0%	4.0%(3)
Ken Maples	2.0%	2.0%(4)
Clint Duty		
Michael L. Greenwood		
Edward D. Doherty		
Rayford T. Reid		
Shelby E. Odell		
All directors and executive officers as a group (8 persons)	100.0%	61.7%

(1) Harold Hamm is the sole member of HH GP Holding LLC, which owns a 94.0% Class A membership interest in our general partner. The interests held by HH GP Holding LLC are reported in this table as beneficially owned by Mr. Hamm.

(2) Continental Gas Holdings, Inc. owns a 61.0% Class B membership interest in our general partner. The interest held by Continental Gas Holdings, Inc. is reported in this table as beneficially owned by Mr. Hamm, the Harold Hamm DST Trust and the Harold Hamm HJ Trust in proportion to their respective ownership of Continental Gas Holdings, Inc.

(3) Includes a 3.3% unvested Class B membership interest that vests in equal increments annually over a three year period commencing on February 15, 2005.

(4) Represents an unvested Class B membership interest that vests in equal increments annually over a three year period commencing on February 15, 2005.

Under the terms of our general partner's limited liability company agreement, its membership interests are divided into two classes Class A Units and Class B Units. Except as described below, only holders of Class A Units are entitled to vote on matters submitted to the members for approval, including the election of our general partner's directors. Class B Units are not entitled to vote on any matters other than any consolidation, merger, liquidation, dissolution or winding-up of our general partner or any sale by our general partner of all or substantially all of its assets. Distributions by our general partner to its members shall be made only to holders of Class B Units in respect of their Class B Units on a pro rata basis. Holders of Class A Units will generally not be entitled to receive any distributions from our general partner in respect of their Class A Units.

Generally, no member may transfer their interests in our general partner without the approval of the holders of a majority of the Class A Units. Harold Hamm and certain of his affiliates and any other holder of Class A Units or Class B Units who, together with its affiliates holds at least a majority of the outstanding Class A Units, has the right to transfer units to another person without the approval of the board of directors or any member of our general partner. In addition, if one or more holders of Class B Units proposes to transfer Class B Units representing 50% or more of the outstanding Class B Units, then such selling holders have the right to require all other holders of Class B Units to sell their Class B Units to the proposed transferee on the same terms.

A portion of Mr. Moeder's Class B Units and all of Mr. Maples' Class B Units are unvested and will vest in equal increments annually over a three-year period commencing on February 15, 2005. In addition, any unvested units will become fully vested upon the disability, death or termination other than for cause of such individual or a change of control of our general partner. If Messrs. Moeder or Maples cease to be an officer or employee of our general partner for any reason, then our general partner has the right to purchase all of such individual's vested Class B Units for fair market value and all of such individual's Class A Units and unvested Class B Units for nominal consideration. In addition, if Messrs. Moeder or Maples becomes disabled, dies or is terminated without cause, such individual will be entitled to sell his units to our general partner at those same prices.

CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

After this offering, the general partner and its affiliates will own 467,423 common units and 4,080,000 subordinated units representing a 53.0% limited partner interest in us. In addition, the general partner will continue to own a 2% general partner interest in us and the incentive distribution rights.

Distributions and Payments to Our General Partner and its Affiliates

Our general partner and its affiliates do not receive any management fee or other compensation for the management of our business and affairs, but they are reimbursed for all expenses that they incur on our behalf, including general and administrative expenses, salaries and benefits for all of our employees and other corporate overhead. Our general partner determines the amount of these expenses. In the omnibus agreement, Continental Resources has agreed to continue to provide certain general and administrative services to us for two years after our initial public offering, at the lower of Continental Resources' cost to provide the services and $50,000 per year. Please read " Omnibus Agreement Services" below. In addition, our general partner owns the 2% general partner interest and all of the incentive distribution rights. Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement.

Agreements with Harold Hamm and His Affiliates

Omnibus Agreement

Upon the closing of our initial public offering, we entered into an omnibus agreement with Continental Resources, Hiland Partners, LLC, Harold Hamm, Continental Gas Holdings, Inc. and our general partner that addressed the following matters:

- for a two-year period, Continental Resources will provide certain general and administrative services;
- Harold Hamm's agreement not to compete and to cause his affiliates (including Continental Resources) not to compete with us under certain circumstances;
- an indemnity by Continental Resources, Hiland Partners, LLC and Continental Gas Holdings, Inc. for prior tax liabilities resulting from the assets contributed to the partnership;
- an indemnity by Continental Resources for liabilities associated with oil and gas properties conveyed by Continental Gas to Continental Resources by dividend; and
- our two-year exclusive option to purchase the Bakken gathering system owned by Hiland Partners, LLC.

Services

Continental Resources has agreed to provide us the following services:

- information technology support, including supplying our computer servers, repair services and electronic mail; and
- human resource functions, including locating and recruiting potential employees and assistance in complying with certain employment laws and regulations.

Continental Resources is obligated to provide these services to us for two years after our initial public offering, at the lower of Continental Resources' cost to provide the services or $50,000 per year.

Non-Competition

Harold Hamm will not, and will cause his affiliates not to engage in, whether by acquisition, construction, investment in debt or equity interests of any person or otherwise, the business of gathering, treating, processing and transportation of natural gas in North America, the transportation and fractionation of NGLs in North America, and constructing, buying or selling any assets related to the foregoing businesses. This restriction does not apply to:

- any business that is primarily related to the exploration for and production of oil or natural gas, including the sale and marketing of oil and natural gas derived from such exploration and production activities;
- the purchase and ownership of not more than five percent of any class of securities of any entity engaged in the business described above;
- any business conducted by Harold Hamm or his affiliates as of the date of the omnibus agreement;
- any business that Harold Hamm or his affiliates acquires or constructs that has a fair market value or construction cost, as applicable, of less than $5.0 million;
- any business that Harold Hamm or his affiliates acquires or constructs that has a fair market value or construction cost, as applicable, of $5.0 million or more if we have been offered the opportunity to purchase the business for the fair market value or construction cost, as applicable, and we decline to do so with the concurrence of the conflicts committee of our general partner; and
- any business conducted by Harold Hamm or his affiliates, with the approval of the conflicts committee.

These non-competition obligations will terminate on the first to occur of the following events:

- the first day on which the Hamm Parties no longer control us;
- the death of Harold Hamm; and
- February 15, 2010, the fifth anniversary of the closing of our initial public offering.

Indemnification

Continental Resources, Hiland Partners, LLC and Continental Gas Holdings, Inc. agreed to indemnify us for all federal, state and local income tax liabilities attributable to the operation of the assets contributed by such entities to us prior to the closing of our initial public offering. In addition, Continental Resources agreed to indemnify us for a period of five years from the closing date of our initial public offering for liabilities associated with oil and gas properties conveyed by Continental Gas to Continental Resources by dividend.

Option to Purchase the Bakken Gathering System

The omnibus agreement also contains the terms under which we held an option to purchase the Bakken gathering system from Hiland Partners, LLC. Pursuant to the acquisition agreement described below, the omnibus agreement was amended to provide for the purchase of the membership interests in Hiland Partners, LLC instead of the Bakken gathering system, and in September 2005 we purchased all of the outstanding membership interests in Hiland Partners, LLC.

Acquisition Agreement

On September 9, 2005, we, through our operating company, entered into an acquisition agreement with Hiland Partners, LLC and its members pursuant to which we acquired the outstanding membership interests in Hiland Partners, LLC for approximately $92.7 million in cash, consisting of a cash payment of approximately $57.7 million to the former members of Hiland Partners, LLC and the repayment of approximately $35.0 million of bank indebtedness of Hiland Partners, LLC. The acquisition closed on September 26, 2005 and had an effective date of September 1, 2005. The membership interests in Hiland Partners, LLC acquired by us were owned 49% by Harold Hamm, 49% by the Hamm Trusts, and 2% by Equity Financial Services, Inc., whose sole shareholder, director and executive officer is Randy Moeder. Accordingly, Mr. Hamm, the Hamm Trusts and Equity Financial

Services, Inc. will receive approximately $28.3 million, $28.3 million and $1.2 million, respectively, in connection with the transaction, subject to certain closing adjustments. A mutually-agreed-upon investment banking firm determined the fair market value of the Bakken gathering system, the principal asset of Hiland Partners, LLC, and the conflicts committee of the board of directors of our general partner, consisting of its independent directors, approved the transaction.

Contracts with Continental Resources, Inc.

Compression Services Agreement

Prior to our initial public offering, Hiland Partners, LLC leased certain compression assets (which were contributed to us in connection with our initial public offering) to Continental Resources. Hiland Partners, LLC received $244,000, $3.3 million and $3.9 million for the years ended December 31, 2002, 2003 and 2004 under this arrangement. In connection with our initial public offering, we entered into a four-year compression services agreement with Continental Resources as described under "Management's Discussion and Analysis of Financial Condition and Results of Operations Our Contracts Compression Services Agreement." For the nine months ended September 30, 2005, we received revenues of $3.0 million from Continental Resources under this arrangement.

Gas Purchase Contracts

We purchase natural gas and NGLs from Continental Resources and its affiliates. We purchased natural gas and NGLs from Continental Resources and its affiliates in the amount of approximately $13.3 million, $26.2 million and $27.6 million for the years ended December 31, 2002, 2003 and 2004, respectively, and $20.3 million and $26.8 million for the nine months ended September 30, 2004 and 2005, respectively. Hiland Partners, LLC purchased natural gas and NGLs from Continental Resources and its affiliates in the amount of approximately $0.6 million, $1.1 million, and $1.8 million for the years ended December 31, 2002, 2003 and 2004, respectively, and $1.0 million and $4.6 million for the nine months ended September 30, 2004 and 2005, respectively.

Badlands Purchase Contract

On November 8, 2005, we entered into a new 15-year definitive gas purchase agreement with Continental Resources, Inc. under which we will gather, treat and process additional natural gas, which is produced as a by-product of Continental Resources' secondary oil recovery operations, in the areas specified by the contract. In return, we will receive 50% of the proceeds attributable to residue gas and natural gas liquids sales as well as certain fixed fees associated with gathering and treating the natural gas, including a $0.60 per Mcf fee for the first 36 Bcf of natural gas gathered. The board of directors, as well as the conflicts committee of the board of directors, of our general partner have approved the agreement.

In order to fulfill our obligations under the agreement, we intend to expand our Badlands gas gathering system and processing plant located in Bowman County, North Dakota. This expansion project will include the construction of a 40,000 Mcf/d nitrogen rejection plant and the expansion of our existing Badlands field gathering infrastructure. The expansion project, which is targeted for completion in the 4th quarter of 2006, is expected to cost approximately $40 million, which we intend to fund using our existing bank credit facility. Moreover, we expect to spend an additional $9.5 million in 2007 to expand the system.

Other Agreements

Historically, our predecessor and Hiland Partners, LLC have contracted for down hole well services, fluid supply and oil field services from businesses in which Harold Hamm and members of his family have historically owned equity interests. Mr. Hamm and members of his family sold these businesses to Complete Production Services, Inc. in October 2004. Mr. Hamm is currently a director and stockholder of Complete Production Services. Payments made for these services by our predecessor and Hiland Partners, LLC on a combined basis were $188,000, $225,000 and $257,000 during the years ended December 31, 2002, 2003 and 2004, respectively. Payments made for these services were $181,000 and $209,000 for the nine months ended September 30, 2004 and 2005, respectively. We continued to obtain services from these companies following completion of our initial public offering. Based on various bids received by our general partner from unaffiliated third parties, our general partner believes that amounts paid for these services are comparable to those amounts which would be charged by an unaffiliated third party.

In addition, in prior periods Hiland Partners, LLC compensated Equity Financial Services, Inc., an entity wholly owned by our President, Randy Moeder, for management and administrative services. Total payments to Equity Financial Services were approximately $120,000, $65,000 and $65,000 during the years ended December 31, 2002, 2003 and 2004, respectively, and $40,000 and $11,000 during the nine months ended September 30, 2004 and 2005, respectively. Following completion of our initial public offering, this service arrangement was terminated.

We lease office space under operating leases from an entity which is wholly owned by Harold Hamm. Rents paid under these leases totaled approximately $31,000, $47,000 and $51,000 for the years ended December 31, 2002, 2003 and 2004, respectively, and $32,000 and $57,000 for the nine months ended September 30, 2004 and 2005, respectively. These rates are consistent with the rates charged to other non-affiliated tenants in the offices.

In connection with the completion of our initial public offering, we adopted an ethics policy which requires that related party transactions be reviewed to ensure that they are fair and reasonable to us. This requirement is also contained in our partnership agreement.

CONFLICTS OF INTEREST AND FIDUCIARY DUTIES

Conflicts of Interest

Conflicts of interest exist and may arise in the future as a result of the relationships between our general partner and its affiliates (including its owners) on the one hand, and our partnership and our limited partners, on the other hand. The directors and officers of our general partner have fiduciary duties to manage our general partner in a manner beneficial to its owners. At the same time, our general partner has a fiduciary duty to manage our partnership in a manner beneficial to us and our unitholders.

Whenever a conflict arises between our general partner or its affiliates, on the one hand, and us or any other partner, on the other hand, our general partner will resolve that conflict. Our partnership agreement contains provisions that modify and limit our general partner's fiduciary duties to the unitholders. Our partnership agreement also restricts the remedies available to unitholders for actions taken that, without those limitations, might constitute breaches of fiduciary duty.

Our general partner will not be in breach of its obligations under the partnership agreement or its duties to us or our unitholders if the resolution of the conflict is:

- approved by the conflicts committee, although our general partner is not obligated to seek such approval;
- approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner or any of its affiliates;
- on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
- fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

Our general partner may, but is not required to, seek the approval of such resolution from the conflicts committee of its board of directors. If our general partner does not seek approval from the conflicts committee and its board of directors determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the third and fourth bullet points above, then it will be presumed that, in making its decision, the board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. Unless the resolution of a conflict is specifically provided for in our partnership agreement, our general partner or the conflicts committee may consider any factors it determines in good faith to consider when resolving a conflict. Our partnership agreement provides that in order for a determination or other action to be in good faith, the person or persons making such determination or taking or declining to take such other action must reasonably believe that the determination or other action is in the best interests of the partnership, unless the context otherwise requires.

Conflicts of interest could arise in the situations described below, among others.

Actions taken by our general partner may affect the amount of cash available for distribution to unitholders or accelerate the right to convert subordinated units.

The amount of cash that is available for distribution to unitholders is affected by decisions of our general partner regarding such matters as:

- amount and timing of asset purchases and sales;
- cash expenditures;

- borrowings;
- the issuance of additional units; and
- the creation, reduction or increase of reserves in any quarter.

In addition, borrowings by us and our affiliates do not constitute a breach of any duty owed by our general partner to the unitholders, including borrowings that have the purpose or effect of:

- enabling our general partner to receive distributions on any subordinated units held by our general partner or the incentive distribution rights; or
- hastening the expiration of the subordination period.

For example, in the event we have not generated sufficient cash from our operations to pay the minimum quarterly distribution on our common units and subordinated units, our partnership agreement permits us to borrow funds, which may enable us to make this distribution on all outstanding units. Please read "Our Cash Distribution Policy and Restrictions on Distributions Subordination Period."

Our partnership agreement provides that we and our subsidiaries may borrow funds from our general partner and its affiliates. Our general partner and its affiliates may not borrow funds from us or our subsidiaries.

We do not have any officers or employees and rely solely on officers and employees of Hiland Partners GP, LLC and its affiliates.

Affiliates of our general partner conduct businesses and activities of their own in which we have no economic interest. If these separate activities are significantly greater than our activities, there could be material competition for the time and effort of the officers and employees who provide services to our general partner. The officers and employees of our general partner are not required to work full time on our affairs. Certain of our general partner's employees provide services to Continental Resources in connection with the operation of compression assets owned by Continental Resources. In addition, certain of the officers of our general partner, including the chief executive officer and chief financial officer, will also serve as officers of affiliates of the general partner.

We will reimburse our general partner and its affiliates for expenses.

We will reimburse our general partner and its affiliates for costs incurred in managing and operating us, including costs incurred in rendering corporate staff and support services to us. The partnership agreement provides that our general partner will determine the expenses that are allocable to us in good faith.

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit its liability under contractual arrangements so that the other party has recourse only to our assets, and not against our general partner or its assets. The partnership agreement provides that any action taken by our general partner to limit its liability or our liability is not a breach of our general partner's fiduciary duties, even if we could have obtained more favorable terms without the limitation on liability.

Common unitholders will have no right to enforce obligations of our general partner and its affiliates under agreements with us.

Any agreements between us on the one hand, and our general partner and its affiliates, on the other, will not grant to the unitholders, separate and apart from us, the right to enforce the obligations of our general partner and its affiliates in our favor.

Contracts between us, on the one hand, and our general partner and its affiliates, on the other, will not be the result of arm's length negotiations.

Our partnership agreement allows our general partner to determine, in good faith, any amounts to pay itself or its affiliates for any services rendered to us. Our general partner may also enter into additional contractual arrangements with any of its affiliates on our behalf. Neither the partnership agreement nor any of the other agreements, contracts and arrangements between us, on the one hand, and our general partner and its affiliates, on the other, are or will be the result of arm's length negotiations.

The general partner will determine, in good faith, the terms of any of these transactions entered into after the sale of the common units offered in this offering.

Our general partner and its affiliates will have no obligation to permit us to use any facilities or assets of our general partner and its affiliates, except as may be provided in contracts entered into specifically dealing with that use. There will not be any obligation of our general partner and its affiliates to enter into any contracts of this kind.

Common units are subject to our general partner's limited call right.

Our general partner may exercise its right to call and purchase common units as provided in the partnership agreement or assign this right to one of its affiliates or to us. Our general partner may use its own discretion, free of fiduciary duty restrictions, in determining whether to exercise this right. As a result, a common unitholder may have his common units purchased from him at an undesirable time or price. Please read "The Partnership Agreement Limited Call Right."

We may not choose to retain separate counsel for ourselves or for the holders of common units.

The attorneys, independent accountants and others who have performed services for us regarding the offering have been retained by our general partner. Attorneys, independent accountants and others who will perform services for us are selected by our general partner or the conflicts committee and may perform services for our general partner and its affiliates. We may retain separate counsel for ourselves or the holders of common units in the event of a conflict of interest between our general partner and its affiliates, on the one hand, and us or the holders of common units, on the other, depending on the nature of the conflict. We do not intend to do so in most cases.

Our general partner's affiliates may compete with us.

Our partnership agreement provides that our general partner will be restricted from engaging in any business activities other than those incidental to its ownership of interests in us. Under the omnibus agreement, Harold Hamm and his affiliates have agreed not to engage in the businesses described under "Certain Relationships and Related Transactions Omnibus Agreement Noncompetition," subject to certain limitations. Except as provided in our partnership agreement and the omnibus agreement, affiliates of our general partner are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us.

Fiduciary Duties

Our general partner is accountable to us and our unitholders as a fiduciary. Fiduciary duties owed to unitholders by our general partner are prescribed by law and the partnership agreement. The Delaware Revised Uniform Limited Partnership Act, which we refer to in this prospectus as the Delaware Act, provides that Delaware limited partnerships may, in their partnership agreements, modify, restrict or expand the fiduciary duties otherwise owed by a general partner to limited partners and the partnership.

Our partnership agreement contains various provisions modifying and restricting the fiduciary duties that might otherwise be owed by our general partner. We have adopted these restrictions to allow our general partner or its affiliates to engage in transactions with us that would otherwise be prohibited by state-law fiduciary duty standards and to take into account the interests of other parties in addition to our interests when resolving conflicts of interest. Without such modifications, transactions such as the conveyance of the Bakken gathering system to us and future natural gas supply agreements entered into with Continental Resources could result in violations of the general partner's state-law fiduciary duty standards. We believe this is appropriate and necessary because our general partner's board of directors have fiduciary duties to manage our general partner in a manner beneficial to its owners, as well as to you. Without these modifications, the general partner's ability to make decisions involving conflicts of interest would be restricted. The modifications to the fiduciary standards enable the general partner to take into consideration all parties involved in the proposed action, so long as the resolution is fair and reasonable to us as described below. These modifications also enable our general partner to attract and retain experienced and capable directors. These modifications are detrimental to the common unitholders because they restrict the remedies available to unitholders for actions that, without those limitations, might constitute breaches of fiduciary duty, as described below, and permit our general partner to take into account the interests of third parties in addition to our interests when resolving conflicts of interest. The following is a summary of the material restrictions of the fiduciary duties owed by our general partner to the limited partners:

State law fiduciary duty standards	Fiduciary duties are generally considered to include an obligation to act in good faith and with due care and loyalty. The duty of care, in the absence of a provision in a partnership agreement providing otherwise, would generally require a general partner to act for the partnership in the same manner as a prudent person would act on his own behalf. The duty of loyalty, in the absence of a provision in a partnership agreement providing otherwise, would generally prohibit a general partner of a Delaware limited partnership from taking any action or engaging in any transaction where a conflict of interest is present.
	The Delaware Act generally provides that a limited partner may institute legal action on behalf of the partnership to recover damages from a third party where a general partner has refused to institute the action or where an effort to cause a general partner to do so is not likely to succeed. In addition, the statutory or case law of some jurisdictions may permit a limited partner to institute legal action on behalf of himself and all other similarly situated limited partners to recover damages from a general partner for violations of its fiduciary duties to the limited partners.

Partnership agreement modified standards	Our partnership agreement contains provisions that waive or consent to conduct by our general partner and its affiliates that might otherwise raise issues about compliance with fiduciary duties or applicable law. For example, our partnership agreement provides that when our general partner is acting in its capacity as our general partner, as opposed to in its individual capacity, it must act in "good faith" and will not be subject to any other standard under applicable law. In addition, when our general partner is acting in its individual capacity, as opposed to in its capacity as our general partner, it may act without any fiduciary obligation to us or the unitholders whatsoever. These standards reduce the obligations to which our general partner would otherwise be held.
	In addition to the other more specific provisions limiting the obligations of our general partner, our partnership agreement further provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for errors of judgment or for any acts or omissions unless there has been a final and non appealable judgment by a court of competent jurisdiction determining that the general partner or its officers and directors acted in bad faith or engaged in fraud, willful misconduct or, in the case of a criminal matter, acted with knowledge that such person's conduct was criminal.
	Special provisions regarding affiliated transactions. Our partnership agreement generally provides that affiliated transactions and resolutions of conflicts of interest not involving a vote of unitholders and that are not approved by the conflicts committee of the board of directors of our general partner must be:
	on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
	"fair and reasonable" to us, taking into account the totality of the relationships between the parties involved (including other transactions that may be particularly favorable or advantageous to us).
	If our general partner does not seek approval from the conflicts committee and its board of directors determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the bullet points above, then it will be presumed that, in making its decision, the board of directors, which may include board members affected by the conflict of interest, acted in good faith and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. These standards reduce the obligations to which our general partner would otherwise be held.

Each common unitholder automatically agrees to be bound by the provisions in the partnership agreement, including the provisions discussed above. This is in accordance with the policy of the Delaware Act favoring the principle of freedom of contract and the enforceability of partnership agreements. The failure of a limited partner or assignee to sign a partnership agreement does not render the partnership agreement unenforceable against that person.

We must indemnify our general partner and its officers, directors, managers and certain other specified persons, to the fullest extent permitted by law, against liabilities, costs and expenses incurred by our general partner or these other persons. We must provide this indemnification unless there has been a final and non-appealable judgment by a court of competent jurisdiction determining that these persons acted in bad faith or engaged in fraud, willful misconduct or, in the case of a criminal matter, acted with knowledge that such person's conduct was criminal. We must also provide this indemnification for criminal proceedings unless our general partner or these other persons acted with knowledge that their conduct was unlawful. Thus, our general partner could be indemnified for its negligent acts if it met the requirements set forth above. To the extent these provisions purport to include indemnification for liabilities arising under the Securities Act, in the opinion of the SEC, such indemnification is contrary to public policy and, therefore, unenforceable. Please read "The Partnership Agreement Indemnification."

DESCRIPTION OF THE COMMON UNITS

The Units

The common units and the subordinated units represent limited partner interests in us. The holders of units are entitled to participate in partnership distributions and exercise the rights or privileges available to limited partners under our partnership agreement. For a description of the relative rights and preferences of holders of common units and subordinated units in and to partnership distributions, please read this section and "Our Cash Distribution Policy and Restrictions on Distributions." For a description of the rights and privileges of limited partners under our partnership agreement, including voting rights, please read "The Partnership Agreement."

Transfer Agent and Registrar

Duties. American Stock Transfer & Trust Company serves as registrar and transfer agent for the common units. We pay all fees charged by the transfer agent for transfers of common units except the following that must be paid by unitholders:

- surety bond premiums to replace lost or stolen certificates, taxes and other governmental charges;
- special charges for services requested by a common unitholder; and
- other similar fees or charges.

There is no charge to unitholders for disbursements of our cash distributions. We will indemnify the transfer agent, its agents and each of their stockholders, directors, officers and employees against all claims and losses that may arise out of acts performed or omitted for its activities in that capacity, except for any liability due to any gross negligence or intentional misconduct of the indemnified person or entity.

Resignation or Removal. The transfer agent may resign, by notice to us, or be removed by us. The resignation or removal of the transfer agent will become effective upon our appointment of a successor transfer agent and registrar and its acceptance of the appointment. If no successor has been appointed and his accepted the appointment within 30 days after notice of the resignation or removal, our general partner may act as the transfer agent and registrar until a successor is appointed.

Transfer of Common Units

By transfer of common units in accordance with our partnership agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission is reflected in our books and records. Each transferee:

- represents that the transferee has the capacity, power and authority to become bound by our partnership agreement;
- automatically agrees to be bound by the terms and conditions of, and is deemed to have executed, our partnership agreement; and
- gives the consents and approvals contained in our partnership agreement, such as the approval of all transactions and agreements that we are entering into in connection with our formation and this offering.

A transferee will become a substituted limited partner of our partnership for the transferred common units automatically upon the recording of the transfer on our books and records. The general partner will cause any transfers to be recorded on our books and records no less frequently than quarterly.

We may, at our discretion, treat the nominee holder of a common unit as the absolute owner. In that case, the beneficial holders' rights are limited solely to those that it has against the nominee holder as a result of any agreement between the beneficial owner and the nominee holder.

Common units are securities and are transferable according to the laws governing transfers of securities. In addition to other rights acquired upon transfer, the transferor gives the transferee the right to become a substituted limited partner in our partnership for the transferred common units.

Until a common unit has been transferred on our books, we and the transfer agent may treat the record holder of the unit as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations.

DESCRIPTION OF THE SUBORDINATED UNITS

The subordinated units are a separate class of limited partner interests in our partnership, and the rights of holders of subordinated units to participate in distributions to unitholders differ from, and are subordinated to, the rights of the holders of common units. Unlike the common units, the subordinated units will not be publicly traded.

Cash Distribution Policy

During the subordination period, the common units will have the right to receive distributions of available cash from operating surplus in an amount equal to the minimum quarterly distribution of $0.45 per unit, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. The purpose of the subordinated units is to increase the likelihood that during the subordination period there will be available cash to be distributed on the common units. Please read "Our Cash Distribution Policy and Restrictions or Distributions Distributions of Available Cash from Operating Surplus during the Subordination Period."

Conversion of the Subordinated Units

Each subordinated unit will convert into one common unit at the end of the subordination period, which will end once we meet the financial tests stated in our partnership agreement up to 50% of the subordinated units may convert prior to the end of the subordination period if we meet certain financial tests. The subordination period will extend until the first day of any quarter beginning after March 31, 2010 that each of the following tests is met:

- distributions of available cash from operating surplus on each of the outstanding common units and subordinated units for the three consecutive four-quarter periods immediately preceding that date equaled or exceeded the minimum quarterly distribution;

- the "adjusted operating surplus" generated during the three consecutive four-quarter periods immediately preceding that date equaled or exceeded the sum of the minimum quarterly distributions on all of the outstanding common units and subordinated units during those periods on a fully diluted basis and the related distribution on the 2% general partner interest during those periods; and

- there are no arrearages in payment of the minimum quarterly distribution on the common units.

Any quarterly distributions payable to our existing investors that are used to satisfy any reimbursement obligations associated with our cap on general and administrative expenses shall be considered distributed to such existing investors for purposes of determining whether the tests above have been met. Please read "Our Cash Distribution Policy and Restrictions or Distributions Subordination Period."

Distributions Upon Liquidation

If we liquidate during the subordination period, we will allocate gain and loss to entitle the holders of common units a preference over the holders of subordinated units to the extent required to permit the common unitholders to receive their unrecovered initial unit price, plus the minimum quarterly distribution for the quarter during which liquidation occurs, plus any arrearages. Please read "Our Cash Distribution Policy and Restrictions or Distributions Distributions of Cash Upon Liquidation."

Limited Voting Rights

For a description of the voting rights of holders of subordinated units, please read "The Partnership Agreement Voting Rights."

THE PARTNERSHIP AGREEMENT

The following is a summary of the material provisions of our partnership agreement. We will provide prospective investors with a copy of this agreement upon request at no charge.

We summarize the following provisions of our partnership agreement elsewhere in this prospectus:

- with regard to distributions of available cash, please read "Our Cash Distribution Policy and Restrictions or Distributions;"
- with regard to the transfer of common units, please read "Description of the Common Units Transfer of Common Units;" and
- with regard to allocations of taxable income and taxable loss, please read "Material Tax Consequences."

Organization and Duration

Our partnership was organized on October 18, 2004 and will have a perpetual existence.

Purpose

Our purpose under the partnership agreement is limited to any business activities that are approved by our general partner and that lawfully may be conducted by a limited partnership organized under Delaware law; provided, that our general partner shall not cause us to engage, directly or indirectly, in any business activity that the general partner determines would cause us to be treated as an association taxable as a corporation or otherwise taxable as an entity for federal income tax purposes.

Although our general partner has the ability to cause us, our operating company or its subsidiaries to engage in activities other than the midstream energy business or the compression services business in which we are currently engaged, our general partner has no current plans to do so and may decline to do so free of any fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interests of us or the limited partners. Our general partner is authorized in general to perform all acts it determines to be necessary or appropriate to carry out our purposes and to conduct our business.

Power of Attorney

Each limited partner, and each person who acquires a unit from a unitholder, by accepting the common unit, automatically grants to our general partner and, if appointed, a liquidator, a power of attorney to, among other things, execute and file documents required for our qualification, continuance or dissolution. The power of attorney also grants our general partner the authority to amend, and to make consents and waivers under, our partnership agreement.

Capital Contributions

Unitholders are not obligated to make additional capital contributions, except as described below under " Limited Liability."

Voting Rights

The following is a summary of the unitholder vote required for the matters specified below. Matters requiring the approval of a "unit majority" require:

during the subordination period, the approval of a majority of the common units, excluding those common units held by our general partner and its affiliates, and a majority of the subordinated units, voting as separate classes; and

after the subordination period, the approval of a majority of the common units.

In voting their common and subordinated units, our general partner and its affiliates will have no fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interests of us or the limited partners.

Issuance of additional common units or units of equal rank with the common units during the subordination period	Unit majority, with exceptions described under " Issuance of Additional Securities."
Issuance of units senior to the common units during the subordination period	Unit majority.
Issuance of units junior to the common units during the subordination period	No approval right.
Issuance of additional units after the subordination period	No approval right.
Amendment of the partnership agreement	Certain amendments may be made by the general partner without the approval of the unitholders. Other amendments generally require the approval of a unit majority. Please read " Amendment of the Partnership Agreement."
Merger of our partnership or the sale of all or substantially all of our assets	Unit majority. Please read " Merger, Sale or Other Disposition of Assets."
Dissolution of our partnership	Unit majority. Please read " Termination and Dissolution."
Reconstitution of our partnership upon dissolution	Unit majority. Please read " Termination and Dissolution."
Withdrawal of the general partner	Under most circumstances, the approval of a majority of the common units, excluding common units held by the general partner and its affiliates, is required for the withdrawal of the general partner prior to March 31, 2015 in a manner that would cause a dissolution of our partnership. Please read " Withdrawal or Removal of the General Partner."
Removal of the general partner	Not less than $66\frac{2}{3}\%$ of the outstanding units, including units held by our general partner and its affiliates. Please read " Withdrawal or Removal of the General Partner."

Transfer of the general partner interest	Our general partner may transfer all, but not less than all, of its general partner interest in us without a vote of our unitholders to an affiliate or another person in connection with its merger or consolidation with or into, or sale of all or substantially all of its assets to such person. The approval of a majority of the common units, excluding common units held by the general partner and its affiliates, is required in other circumstances for a transfer of the general partner interest to a third party prior to March 31, 2015. See " Transfer of General Partner Interest."
Transfer of incentive distribution rights	Except for transfers to an affiliate or another person as part of our general partner's merger or consolidation, sale of all or substantially all of its assets or the sale of all of the ownership interests in such holder, the approval of a majority of the common units, excluding common units held by the general partner and its affiliates, is required in most circumstances for a transfer of the incentive distribution rights to a third party prior to March 31, 2015. Please read " Transfer of Incentive Distribution Rights."
Transfer of ownership interests in our general partner	No approval required at any time. Please read " Transfer of Ownership Interests in the General Partner."

Limited Liability

Assuming that a limited partner does not participate in the control of our business within the meaning of the Delaware Act and that he otherwise acts in conformity with the provisions of the partnership agreement, his liability under the Delaware Act will be limited, subject to possible exceptions, to the amount of capital he is obligated to contribute to us for his common units plus his share of any undistributed profits and assets. If it were determined, however, that the right, or exercise of the right, by the limited partners as a group:

- to remove or replace the general partner;
- to approve some amendments to the partnership agreement; or
- to take other action under the partnership agreement;

constituted "participation in the control" of our business for the purposes of the Delaware Act, then the limited partners could be held personally liable for our obligations under the laws of Delaware, to the same extent as the general partner. This liability would extend to persons who transact business with us who reasonably believe that the limited partner is a general partner. Neither the partnership agreement nor the Delaware Act specifically provides for legal recourse against the general partner if a limited partner were to lose limited liability through any fault of the general partner. While this does not mean that a limited partner could not seek legal recourse, we know of no precedent for this type of a claim in Delaware case law.

Under the Delaware Act, a limited partnership may not make a distribution to a partner if, after the distribution, all liabilities of the limited partnership, other than liabilities to partners on account of their partnership interests and liabilities for which the recourse of creditors is limited to specific property of the partnership, would exceed the fair value of the assets of the limited partnership. For the purpose of determining the fair value of the assets of a limited partnership, the Delaware Act provides that the fair value of property subject to liability for which recourse of creditors is limited shall be included in the assets of the limited partnership only to the extent that the fair value of that property exceeds the nonrecourse liability. The Delaware Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of the Delaware Act shall be liable to the limited partnership for the amount of the distribution for three years. Under the Delaware Act, a substituted limited partner of a limited partnership is liable for the obligations of his assignor to make contributions to the partnership, except that such person is not obligated for liabilities unknown to him at the time he became a limited partner and that could not be ascertained from the partnership agreement.

Our subsidiaries conduct business in six states. Maintenance of our limited liability as a member of the operating company may require compliance with legal requirements in the jurisdictions in which the operating company conducts business, including qualifying our subsidiaries to do business there.

Limitations on the liability of limited partners for the obligations of a limited partner have not been clearly established in many jurisdictions. If, by virtue of our membership interest in the operating company or otherwise, it were determined that we were conducting business in any state without compliance with the applicable limited partnership or limited liability company statute, or that the right or exercise of the right by the limited partners as a group to remove or replace the general partner, to approve some amendments to the partnership agreement, or to take other action under the partnership agreement constituted "participation in the control" of our business for purposes of the statutes of any relevant jurisdiction, then the limited partners could be held personally liable for our obligations under the law of that jurisdiction to the same extent as the general partner under the circumstances. We will operate in a manner that the general partner considers reasonable and necessary or appropriate to preserve the limited liability of the limited partners.

Issuance of Additional Securities

Our partnership agreement authorizes us to issue an unlimited number of additional common units and other equity securities for the consideration and on the terms and conditions determined by our general partner without the approval of the unitholders. During the subordination period, however, except as we discuss in the following paragraph, we may not issue equity securities ranking senior to the common units or an aggregate of more than 1,360,000 additional common units or units on a parity with the common units, in each case, without the approval of the holders of a unit majority.

During the subordination period or thereafter, we may issue an unlimited number of common units without the approval of the unitholders as follows:

- upon conversion of the subordinated units;
- under employee benefits plans;
- upon conversion of the general partner interests and incentive distribution rights as a result of a withdrawal or removal of our general partner;
- upon conversion of units of equal rank with the common units into common units under certain circumstances;
- in the event of a combination or subdivision of common units;

- in connection with an acquisition or an expansion capital improvement that increases cash flow from operations per unit on an estimated pro forma basis;

- if the proceeds of the issuance are used to repay indebtedness, the cost of which to service is greater than the distribution obligations associated with the units issued in connection with its retirement; or

- in connection with the redemption of common units or other equity interests of equal rank with the common units from the net proceeds of an issuance of common units or parity units, but only if the redemption price equals the net proceeds per unit, before expenses, to us.

It is possible that we will fund acquisitions through the issuance of additional common units, subordinated units or other partnership securities. Holders of any additional common units we issue will be entitled to share equally with the then-existing holders of common units in our distributions of available cash. In addition, the issuance of additional common units or other partnership securities may dilute the value of the interests of the then-existing holders of common units in our net assets.

In accordance with Delaware law and the provisions of our partnership agreement, we may also issue additional partnership securities that, as determined by our general partner, may have special voting rights to which the common units are not entitled. In addition, our partnership agreement does not prohibit the issuance by our subsidiaries of equity securities, which may effectively rank senior to the common units.

Upon issuance of additional partnership securities, our general partner will be entitled, but not required, to make additional capital contributions to the extent necessary to maintain its 2% general partner interest in us. The general partner's 2% interest in us will be reduced if we issue additional units in the future and our general partner does not contribute a proportionate amount of capital to us to maintain its 2% general partner interest. Moreover, our general partner will have the right, which it may from time to time assign in whole or in part to any of its affiliates, to purchase common units, subordinated units or other partnership securities whenever, and on the same terms that, we issue those securities to persons other than our general partner and its affiliates, to the extent necessary to maintain the percentage interest of the general partner and its affiliates, including such interest represented by common units and subordinated units, that existed immediately prior to each issuance. The holders of common units will not have preemptive rights to acquire additional common units or other partnership securities.

Amendment of the Partnership Agreement

General. Amendments to our partnership agreement may be proposed only by or with the consent of our general partner. However, our general partner will have no duty or obligation to propose any amendment and may decline to do so free of any fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interests of us or the limited partners. In order to adopt a proposed amendment, other than the amendments discussed below, our general partner is required to seek written approval of the holders of the number of units required to approve the amendment or call a meeting of the limited partners to consider and vote upon the proposed amendment. Except as described below, an amendment must be approved by a unit majority.

Prohibited Amendments. No amendment may be made that would:

- enlarge the obligations of any limited partner without its consent, unless approved by at least a majority of the type or class of limited partner interests so affected;

- enlarge the obligations of, restrict in any way any action by or rights of, or reduce in any way the amounts distributable, reimbursable or otherwise payable by us to our general partner or any of its affiliates without the consent of our general partner, which consent may be given or withheld at its option;

change the term of our partnership;

provide that our partnership is not dissolved upon an election to dissolve our partnership by our general partner that is approved by a unit majority; or

give any person the right to dissolve our partnership other than our general partner's right to dissolve our partnership with the approval of a unit majority.

The provision of our partnership agreement preventing the amendments having the effects described in any of the clauses above can be amended upon the approval of the holders of at least 90% of the outstanding units voting together as a single class (including units owned by the general partner and its affiliates). Upon completion of the offering, our general partner and its affiliates will own approximately 54.1% of the outstanding units.

No Unitholder Approval. Our general partner may generally make amendments to our partnership agreement without the approval of any limited partner or assignee to reflect:

a change in our name, the location of our principal place of our business, our registered agent or our registered office;

the admission, substitution, withdrawal or removal of partners in accordance with our partnership agreement;

a change that our general partner determines to be necessary or appropriate to qualify or continue our qualification as a limited partnership or a partnership in which the limited partners have limited liability under the laws of any state or to ensure that neither we nor the operating company nor any of its subsidiaries will be treated as an association taxable as a corporation or otherwise taxed as an entity for federal income tax purposes;

an amendment that is necessary, in the opinion of our counsel, to prevent us or our general partner or its directors, officers, agents or trustees from in any manner being subjected to the provisions of the Investment Company Act of 1940, the Investment Advisors Act of 1940, or "plan asset" regulations adopted under the Employee Retirement Income Security Act of 1974, or ERISA, whether or not substantially similar to plan asset regulations currently applied or proposed;

subject to the limitations on the issuance of additional partnership securities described above, an amendment that our general partner determines to be necessary or appropriate for the authorization of additional partnership securities or rights to acquire partnership securities;

any amendment expressly permitted in our partnership agreement to be made by our general partner acting alone;

an amendment effected, necessitated or contemplated by a merger agreement that has been approved under the terms of our partnership agreement;

any amendment that our general partner determines to be necessary or appropriate for the formation by us of, or our investment in, any corporation, partnership or other entity, as otherwise permitted by our partnership agreement;

a change in our fiscal year or taxable year and related changes;

mergers with or conveyances to another limited liability entity that is newly formed and has no assets, liabilities or operations at the time of the merger or conveyance other than those it receives by way of the merger or conveyance; or any other amendments substantially similar to any of the matters described in the clauses above.

In addition, our general partner may make amendments to our partnership agreement without the approval of any limited partner or assignee if the general partner determines that those amendments:

do not adversely affect the limited partners (or any particular class of limited partners) in any material respect;

are necessary or appropriate to satisfy any requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any federal or state agency or judicial authority or contained in any federal or state statute;

are necessary or appropriate to facilitate the trading of limited partner interests or to comply with any rule, regulation, guideline or requirement of any securities exchange on which the limited partner interests are or will be listed for trading;

are necessary or appropriate for any action taken by our general partner relating to splits or combinations of units under the provisions of our partnership agreement; or

are required to effect the intent expressed in this prospectus or the intent of the provisions of our partnership agreement or are otherwise contemplated by our partnership agreement.

Opinion of Counsel and Unitholder Approval. Our general partner will not be required to obtain an opinion of counsel that an amendment will not result in a loss of limited liability to the limited partners or result in our being treated as an entity for federal income tax purposes in connection with any of the amendments described under " No Unitholder Approval." No other amendments to our partnership agreement will become effective without the approval of holders of at least 90% of the outstanding units voting as a single class unless we first obtain an opinion of counsel to the effect that the amendment will not affect the limited liability under applicable law of any of our limited partners.

In addition to the above restrictions, any amendment that would have a material adverse effect on the rights or preferences of any type or class of outstanding units in relation to other classes of units will require the approval of at least a majority of the type or class of units so affected. Any amendment that reduces the voting percentage required to take any action is required to be approved by the affirmative vote of limited partners whose aggregate outstanding units constitute not less than the voting requirement sought to be reduced.

Merger, Sale or Other Disposition of Assets

A merger or consolidation of us requires the prior consent of our general partner. However, our general partner will have no duty or obligation to consent to any merger or consolidation and may decline to do so free of any fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interest of us or the limited partners.

In addition, the partnership agreement generally prohibits the general partner without the prior approval of the holders of a unit majority, from causing us to, among other things, sell, exchange or otherwise dispose of all or substantially all of our assets in a single transaction or a series of related transactions, including by way of merger, consolidation or other combination, or approving on our behalf the sale, exchange or other disposition of all or substantially all of the assets of our subsidiaries. Our general partner may, however, mortgage, pledge, hypothecate or grant a security interest in all or substantially all of our assets without that approval. Our general partner may also sell all or substantially all of our assets under a foreclosure or other realization upon those encumbrances without that approval.

If the conditions specified in the partnership agreement are satisfied, our general partner may convert us or any of our subsidiaries into a new limited liability entity or merge us or any of our subsidiaries into, or convey all of our assets to, a newly formed entity if the sole purpose of that merger or conveyance is to effect a mere change in our legal form into another limited liability entity. The unitholders are not entitled to dissenters' rights of appraisal under the partnership agreement or applicable Delaware law in the event of a conversion, merger or consolidation, a sale of substantially all of our assets or any other transaction or event.

Termination and Dissolution

We will continue as a limited partnership until terminated under our partnership agreement. We will dissolve upon:

- the election of our general partner to dissolve us, if approved by the holders of units representing a unit majority;
- the sale, exchange or other disposition of all or substantially all of our assets and properties and our subsidiaries;
- the entry of a decree of judicial dissolution of our partnership; or
- the withdrawal or removal of our general partner or any other event that results in its ceasing to be our general partner other than by reason of a transfer of its general partner interest in accordance with our partnership agreement or withdrawal or removal following approval and admission of a successor.

Upon a dissolution under the last clause above, the holders of a unit majority, may also elect, within specific time limitations, to reconstitute us and continue our business on the same terms and conditions described in our partnership agreement by forming a new limited partnership on terms identical to those in our partnership agreement and having as general partner an entity approved by the holders of units representing a unit majority, subject to our receipt of an opinion of counsel to the effect that:

- the action would not result in the loss of limited liability of any limited partner; and
- neither our partnership, the reconstituted limited partnership, our operating company nor any of our other subsidiaries, would be treated as an association taxable as a corporation or otherwise be taxable as an entity for federal income tax purposes upon the exercise of that right to continue.

Liquidation and Distribution of Proceeds

Upon our dissolution, unless we are reconstituted and continued as a new limited partnership, the liquidator authorized to wind up our affairs will, acting with all of the powers of our general partner that are necessary or appropriate to liquidate our assets and apply the proceeds of the liquidation as provided in "Our Cash Distribution Policy and Restrictions on Distributions Distributions of Cash upon Liquidation." The liquidator may defer liquidation or distribution of our assets for a reasonable period of time or distribute assets to partners in kind if it determines that a sale would be impractical or would cause undue loss to our partners.

Withdrawal or Removal of the General Partner

Except as described below, our general partner has agreed not to withdraw voluntarily as our general partner prior to March 31, 2015 without obtaining the approval of the holders of at least a majority of the outstanding common units, excluding common units held by the general partner and its affiliates, and furnishing an opinion of counsel regarding limited liability and tax matters. On or after March 31, 2015, our general partner may withdraw as general partner without first obtaining approval of any unitholder by giving 90 days' written notice, and that withdrawal will not constitute a violation of our partnership agreement. Notwithstanding the information above, our general partner may withdraw without unitholder approval upon 90 days' notice to the limited partners if at least 50% of the outstanding common units are held or controlled by one person and its affiliates other than the general partner and its affiliates. In addition, the partnership agreement permits our general partner in some instances to sell or otherwise transfer all of its general partner interest in us without the approval of the unitholders. Please read " Transfer of General Partner Interest" and " Transfer of Incentive Distribution Rights."

Upon withdrawal of our general partner under any circumstances, other than as a result of a transfer by our general partner of all or a part of its general partner interest in us, the holders of a unit majority, voting as separate classes, may select a successor to that withdrawing general partner. If a successor is not elected, or is elected but an opinion of counsel regarding limited liability and tax matters cannot be obtained, we will be dissolved, wound up and liquidated, unless within a specified period after that withdrawal, the holders of a unit majority agree in writing to continue our business and to appoint a successor general partner. Please read " Termination and Dissolution."

Our general partner may not be removed unless that removal is approved by the vote of the holders of not less than $66^2/_3$% of the outstanding units, voting together as a single class, including units held by our general partner and its affiliates, and we receive an opinion of counsel regarding limited liability and tax matters. Any removal of our general partner is also subject to the approval of a successor general partner by the vote of the holders of a majority of the outstanding common units and subordinated units, voting as separate classes. The ownership of more than $33^1/_3$% of the outstanding units by our general partner and its affiliates would give them the practical ability to prevent our general partner's removal. At the closing of this offering, our general partner and its affiliates will own 54.1% of the outstanding units.

Our partnership agreement also provides that if our general partner is removed as our general partner under circumstances where cause does not exist and units held by the general partner and its affiliates are not voted in favor of that removal:

- the subordination period will end, and all outstanding subordinated units will immediately convert into common units on a one-for-one basis;

- any existing arrearages in payment of the minimum quarterly distribution on the common units will be extinguished; and

- our general partner will have the right to convert its general partner interest and its incentive distribution rights into common units or to receive cash in exchange for those interests based on the fair market value of those interests at that time.

In the event of removal of a general partner under circumstances where cause exists or withdrawal of a general partner where that withdrawal violates our partnership agreement, a successor general partner will have the option to purchase the general partner interest and incentive distribution rights of the departing general partner for a cash payment equal to the fair market value of those interests. Under all other circumstances where a general partner withdraws or is removed by the limited partners, the departing general partner will have the option to require the successor general partner to purchase the general partner interest of the departing general partner and its incentive distribution rights for fair market value. In each case, this fair market value will be determined by agreement between the departing general partner and the successor general partner. If no agreement is reached, an independent investment banking firm or other independent expert selected by the departing general partner and the successor general partner will determine the fair market value. Or, if the departing general partner and the successor general partner cannot agree upon an expert, then an expert chosen by agreement of the experts selected by each of them will determine the fair market value.

If the option described above is not exercised by either the departing general partner or the successor general partner, the departing general partner's general partner interest and its incentive distribution rights will automatically convert into common units equal to the fair market value of those interests as determined by an investment banking firm or other independent expert selected in the manner described in the preceding paragraph.

In addition, we will be required to reimburse the departing general partner for all amounts due the departing general partner, including, without limitation, all employee related liabilities, including severance liabilities, incurred for the termination of any employees employed by the departing general partner or its affiliates for our benefit.

Transfer of General Partner Interest

Except for transfer by our general partner of all, but not less than all, of its general partner interest in our partnership to:

- an affiliate of our general partner (other than an individual); or
- another entity as part of the merger or consolidation of our general partner with or into another entity or the transfer by our general partner of all or substantially all of its assets to another entity,

our general partner may not transfer all or any part of its general partner interest in our partnership to another person prior to March 31, 2015 without the approval of the holders of at least a majority of the outstanding common units, excluding common units held by our general partner and its affiliates. As a condition of this transfer, the transferee must assume, among other things, the rights and duties of our general partner, agree to be bound by the provisions of our partnership agreement, and furnish an opinion of counsel regarding limited liability and tax matters.

Our general partner and its affiliates may at any time, transfer subordinated units or units to one or more persons, without unitholder approval, except that they may not transfer subordinated units to us.

Transfer of Ownership Interests in the General Partner

At any time, the members of our general partner may sell or transfer all or part of their membership interest in our general partner to an affiliate or third party without the approval of our unitholders.

Transfer of Incentive Distribution Rights

Our general partner or its affiliates or a subsequent holder may transfer its incentive distribution rights to an affiliate of the holder (other than an individual) or another entity as part of the merger or consolidation of such holder with or into another entity, the sale of all of the ownership interest of the holder or the sale of all or substantially all of its assets to, that entity without the prior approval of the unitholders. Prior to March 31, 2015, other transfers of incentive distribution rights will require the affirmative vote of holders of a majority of the outstanding common units, excluding common units held by our general partner and its affiliates. On or after March 31, 2015, the incentive distribution rights will be freely transferable.

Change of Management Provisions

Our partnership agreement contains specific provisions that are intended to discourage a person or group from attempting to remove Hiland Partners GP, LLC as our general partner or otherwise change our management. If any person or group other than our general partner and its affiliates acquires beneficial ownership of 20% or more of any class of units, that person or group loses voting rights on all of its units. This loss of voting rights does not apply to any person or group that acquires the units from our general partner or its affiliates and any transferees of that person or group approved by our general partner or to any person or group who acquires the units with the prior approval of the board of directors of our general partner.

Our partnership agreement also provides that if our general partner is removed under circumstances where cause does not exist and units held by our general partner and its affiliates are not voted in favor of that removal:

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

Limited Call Right

If at any time our general partner and its affiliates own more than 80% of the then-issued and outstanding limited partner interests of any class, our general partner will have the right, which it may assign in whole or in part to any of its affiliates or to us, to acquire all, but not less than all, of the remaining partnership securities of the class held by unaffiliated persons as of a record date to be selected by our general partner, on at least 10 but not more than 60 days notice. The purchase price in the event of this purchase is the greater of:

- the highest cash price paid by either of our general partner or any of its affiliates for any partnership securities of the class purchased within the 90 days preceding the date on which our general partner first mails notice of its election to purchase those limited partner interests; and
- the current market price as of the date three days before the date the notice is mailed.

As a result of our general partner's right to purchase outstanding partnership securities, a holder of partnership securities may have his partnership securities purchased at an undesirable time or price. The tax consequences to a unitholder of the exercise of this call right are the same as a sale by that unitholder of his common units in the market. Please read "Material Tax Consequences Disposition of Common Units."

Meetings; Voting

Except as described below regarding a person or group owning 20% or more of any class of units then outstanding, unitholders or assignees who are record holders of units on the record date will be entitled to notice of, and to vote at, meetings of our limited partners and to act upon matters for which approvals may be solicited. Common units that are owned by an assignee who is a record holder, but who has not yet been admitted as a limited partner, will be voted by our general partner at the written direction of the record holder. Absent direction of this kind, the common units will not be voted, except that, in the case of common units held by our general partner on behalf of non-citizen assignees, our general partner will distribute the votes on those common units in the same ratios as the votes of limited partners on other units are cast.

Our general partner does not anticipate that any meeting of unitholders will be called in the foreseeable future. Any action that is required or permitted to be taken by the unitholders may be taken either at a meeting of the unitholders or without a meeting if consents in writing describing the action so taken are signed by holders of the number of units necessary to authorize or take that action at a meeting. Meetings of the unitholders may be called by our general partner or by unitholders owning at least 20% of the outstanding units of the class for which a meeting is proposed. Unitholders may vote either in person or by proxy at meetings. The holders of a majority of the outstanding units of the class or classes for which a meeting has been called represented in person or by proxy will constitute a quorum unless any action by the unitholders requires approval by holders of a greater percentage of the units, in which case the quorum will be the greater percentage.

Each record holder of a unit has a vote according to his percentage interest in us, although additional limited partner interests having special voting rights could be issued. Please read " Issuance of Additional Securities." However, if at any time any person or group, other than our general partner and its affiliates, or a direct or subsequently approved transferee of our general partner or its affiliates, or a direct or subsequently approved transferee of our general partner or its affiliates, acquires, in the aggregate, beneficial ownership of 20% or more of any class of units then outstanding, that person or group will lose voting rights on all of its units and the units may not be voted on any matter and will not be considered to be outstanding when sending notices of a meeting of unitholders, calculating required votes, determining the presence of a quorum or for other similar purposes. Common units held in nominee or street name account will be voted by the broker or other nominee in accordance with the instruction of the beneficial owner unless the arrangement between the beneficial owner and his nominee provides otherwise. Except as our partnership agreement otherwise provides, subordinated units will vote together with common units as a single class.

Any notice, demand, request, report or proxy material required or permitted to be given or made to record holders of common units under our partnership agreement will be delivered to the record holder by us or by the transfer agent.

Status as Limited Partner

By transfer of common units in accordance with our partnership agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission is reflected in our books and records. Except as described under " Limited Liability," the common units will be fully paid, and unitholders will not be required to make additional contributions.

Non-Citizen Assignees; Redemption

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, we 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, the limited partner may be treated 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.

Indemnification

Under our partnership agreement, in most circumstances, we will indemnify the following persons, to the fullest extent permitted by law, from and against all losses, claims, damages or similar events:

- our general partner;
- any departing general partner;
- any person who is or was an affiliate of a general partner or any departing general partner;
- any person who is or was a director, officer, member, partner, fiduciary or trustee of any entity set forth in the preceding three bullet points;
- any person who is or was serving as director, officer, member, partner, fiduciary or trustee of another person at the request of our general partner or any departing general partner; and
- any person designated by our general partner.

Any indemnification under these provisions will only be out of our assets. Unless it otherwise agrees, our general partner will not be personally liable for, or have any obligation to contribute or loan funds or assets to us to enable us to effectuate, indemnification. We may purchase insurance against liabilities asserted against and expenses incurred by persons for our activities, regardless of whether we would have the power to indemnify the person against liabilities under our partnership agreement.

Reimbursement of Expenses

Our partnership agreement requires us to reimburse our general partner for all direct and indirect expenses it incurs or payments it makes on our behalf and all other expenses allocable to us or otherwise incurred by our general partner in connection with operating our business. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. The general partner is entitled to determine in good faith the expenses that are allocable to us.

Books and Reports

Our general partner is required to keep appropriate books of our business at our principal offices. The books will be maintained for both tax and financial reporting purposes on an accrual basis. For tax and fiscal reporting purposes, our fiscal year is the calendar year.

We will furnish or make available to record holders of common units, within 120 days after the close of each fiscal year, an annual report containing audited financial statements and a report on those financial statements by our independent public accountants. Except for our fourth quarter, we will also furnish or make available summary financial information within 90 days after the close of each quarter.

We will furnish each record holder of a unit with information reasonably required for tax reporting purposes within 90 days after the close of each calendar year. This information is expected to be furnished in summary form so that some complex calculations normally required of partners can be avoided. Our ability to furnish this summary information to unitholders will depend on the cooperation of unitholders in supplying us with specific information. Every unitholder will receive information to assist him in determining his federal and state tax liability and filing his federal and state income tax returns, regardless of whether he supplies us with information.

Right to Inspect Our Books and Records

Our partnership agreement provides that a limited partner can, for a purpose reasonably related to his interest as a limited partner, upon reasonable demand and at his own expense, have furnished to him:

- a current list of the name and last known address of each partner;
- a copy of our tax returns;
- information as to the amount of cash, and a description and statement of the agreed value of any other property or services, contributed or to be contributed by each partner and the date on which each partner became a partner;
- copies of our partnership agreement, our certificate of limited partnership, related amendments and powers of attorney under which they have been executed;
- information regarding the status of our business and financial condition; and
- any other information regarding our affairs as is just and reasonable.

Our general partner may, and intends to, keep confidential from the limited partners trade secrets or other information the disclosure of which our general partner believes in good faith is not in our best interests or that we are required by law or by agreements with third parties to keep confidential.

Registration Rights

Under our partnership agreement, we have agreed to register for resale under the Securities Act and applicable state securities laws any common units, subordinated units or other partnership securities proposed to be sold by our general partner or any of its affiliates or their assignees if an exemption from the registration requirements is not otherwise available. These registration rights continue for two years following any withdrawal or removal of Hiland Partners GP, LLC as general partner. We are obligated to pay all expenses incidental to the registration, excluding underwriting discounts and commissions. Please read "Units Eligible for Future Sale."

UNITS ELIGIBLE FOR FUTURE SALE

After the sale of the common units offered hereby, management of our general partner and the Hamm Parties will hold an aggregate of 467,423 common units and 4,080,000 subordinated units. All of the subordinated units will convert into common units at the end of the subordination period and some may convert earlier. The sale of these units could have an adverse impact on the price of the common units or on any trading market that may develop.

The common units sold in the offering will and the common units issued in our initial public offering are generally be freely transferable without restriction or further registration under the Securities Act, except that any common units owned by an "affiliate" of ours may not be resold publicly except in compliance with the registration requirements of the Securities Act or under an exemption under Rule 144 or otherwise. Rule 144 permits securities acquired by an affiliate of the issuer to be sold into the market in an amount that does not exceed, during any three month period, the greater of:

- 1% of the total number of the securities outstanding; or

- the average weekly reported trading volume of the common units for the four calendar weeks prior to the sale.

Sales under Rule 144 are also subject to specific manner of sale provisions, holding period requirements, notice requirements and the availability of current public information about us. A person who is not deemed to have been an affiliate of ours at any time during the three months preceding a sale, and who has beneficially owned his common units for at least two years, would be entitled to sell common units under Rule 144 without regard to the public information requirements, volume limitations, manner of sale provisions and notice requirements of Rule 144.

Prior to the end of the subordination period, we may not issue equity securities of the partnership ranking prior or senior to the common units or an aggregate of more than 1,360,000 additional common units or an equivalent amount of equity securities ranking on a parity with the common units, without the approval of the holders of a majority of the outstanding common units and subordinated units, voting as separate classes, subject to certain exceptions described under "The Partnership Agreement Issuance of Additional Securities."

Our partnership agreement provides that, after the subordination period, we may issue an unlimited number of limited partner interests of any type without a vote of the unitholders. Our partnership agreement does not restrict our ability to issue equity securities ranking junior to the common units at any time. Any issuance of additional common units or other equity securities would result in a corresponding decrease in the proportionate ownership interest in us represented by, and could adversely affect the cash distributions to and market price of, common units then outstanding. See "The Partnership Agreement Issuance of Additional Securities."

Under our partnership agreement, our general partner and its affiliates have the right to cause us to register under the Securities Act and state securities laws the offer and sale of any common units, subordinated units or other partnership securities that they hold. Subject to the terms and conditions of our partnership agreement, these registration rights allow our general partner and its affiliates or their assignees holding any units or other partnership securities to require registration of any of these units or other partnership securities and to include them in a registration by us of other units, including units offered by us or by any unitholder. Our general partner will continue to have these registration rights for two years following its withdrawal or removal as our general partner. In connection with any registration of this kind, we will indemnify each unitholder participating in the registration and its officers, directors and controlling persons from and against any liabilities under the Securities Act or any state securities laws arising from the registration statement or prospectus. We will bear all costs and expenses incidental to any registration, excluding any underwriting discounts and commissions. Except as described below, our general partner and its affiliates may sell their units or other partnership interests in private transactions at any time, subject to compliance with applicable laws.

The owners of our general partner and their affiliates, including the partnership, our operating company, our general partner and the directors and executive officers of our general partner, have agreed not to sell any common units they beneficially own for a period of 90 days from the date of this prospectus. For a description of these lock-up provisions, please read "Underwriting."

MATERIAL TAX CONSEQUENCES

This section is a discussion of the material tax considerations that may be relevant to prospective unitholders who are individual citizens or residents of the United States and, unless otherwise noted in the following discussion, is the opinion of Vinson & Elkins L.L.P., counsel to the general partner and us, as to all material tax matters and all legal conclusions insofar as it relates to matters of United States federal income tax law and legal conclusions with respect to those matters. This section is based upon current provisions of the Internal Revenue Code, existing and proposed regulations and current administrative rulings and court decisions, all of which are subject to change. Later changes in these authorities may cause the tax consequences to vary substantially from the consequences described below. Unless the context otherwise requires, references in this section to "us" or "we" are references to Hiland Partners, LP and our operating company.

The following discussion does not comment on all federal income tax matters affecting us or the unitholders. Moreover, the discussion focuses on unitholders who are individual citizens or residents of the United States and has only limited application to corporations, estates, trusts, nonresident aliens or other unitholders subject to specialized tax treatment, such as tax-exempt institutions, foreign persons, individual retirement accounts (IRAs), real estate investment trusts (REITs) or mutual funds. Accordingly, we urge each prospective unitholder to consult, and depend on, his own tax advisor in analyzing the federal, state, local and foreign tax consequences particular to him of the ownership or disposition of common units.

All statements as to matters of law and legal conclusions, but not as to factual matters, contained in this section, unless otherwise noted, are the opinion of Vinson & Elkins L.L.P. and are, to the extent noted herein, based on the accuracy of the representations made by us.

No ruling has been or will be requested from the IRS regarding any matter affecting us or prospective unitholders. Instead, we will rely on opinions of Vinson & Elkins L.L.P. Unlike a ruling, an opinion of counsel represents only that counsel's best legal judgment and does not bind the IRS or the courts. Accordingly, the opinions and statements made here may not be sustained by a court if contested by the IRS. Any contest of this sort with the IRS may materially and adversely impact the market for the common units and the prices at which common units trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will result in a reduction in cash available for distribution to our unitholders and our general partner and thus will be borne indirectly by our unitholders and our general partner. Furthermore, the tax treatment of us, or of an investment in us, may be significantly modified by future legislative or administrative changes or court decisions. Any modifications may or may not be retroactively applied.

For the reasons described below, Vinson & Elkins L.L.P. has not rendered an opinion with respect to the following specific federal income tax issues: (1) the treatment of a unitholder whose common units are loaned to a short seller to cover a short sale of common units (please read " Tax Consequences of Unit Ownership Treatment of Short Sales"); (2) whether our monthly convention for allocating taxable income and losses is permitted by existing Treasury Regulations (please read " Disposition of Common Units Allocations Between Transferors and Transferees"); and (3) whether our method for depreciating Section 743 adjustments is sustainable in certain cases (please read " Tax Consequences of Unit Ownership Section 754 Election").

Partnership Status

A partnership is not a taxable entity and incurs no federal income tax liability. Instead, each partner of a partnership is required to take into account his share of items of income, gain, loss and deduction of the partnership in computing his federal income tax liability, regardless of whether cash distributions are made to him by the partnership. Distributions by a partnership to a partner are generally not taxable unless the amount of cash distributed is in excess of the partner's adjusted basis in his partnership interest.

Section 7704 of the Internal Revenue Code provides that publicly traded partnerships will, as a general rule, be taxed as corporations. However, an exception, referred to as the "Qualifying Income Exception," exists with respect to publicly traded partnerships of which 90% or more of the gross income for every taxable year consists of "qualifying income." Qualifying income includes income and gains derived from the transportation, storage, processing and marketing of crude oil, natural gas and products thereof. Other types of qualifying income include interest (other than from a financial business), dividends, gains from the sale of real property and gains from the sale or other disposition of capital assets held for the production of income that otherwise constitutes qualifying income. We estimate that less than 2% of our current income is not qualifying income; however, this estimate could change from time to time. Based upon and subject to this estimate, the factual representations made by us and the general partner and a review of the applicable legal authorities, Vinson & Elkins L.L.P. is of the opinion that at least 90% of our current gross income constitutes qualifying income.

No ruling has been or will be sought from the IRS and the IRS has made no determination as to our status for federal income tax purposes or whether our operations generate "qualifying income" under Section 7704 of the Internal Revenue Code. Instead, we will rely on the opinion of Vinson & Elkins L.L.P. that, based upon the Internal Revenue Code, its regulations, published revenue rulings and court decisions and the representations described below, we will be classified as a partnership and the operating company will be disregarded as an entity separate from us for federal income tax purposes.

In rendering its opinion, Vinson & Elkins L.L.P. has relied on factual representations made by us and the general partner. The representations made by us and our general partner upon which Vinson & Elkins L.L.P. has relied are:

(a) Neither we nor the operating company will elect to be treated as a corporation; and

(b) For each taxable year, more than 90% of our gross income will be income that Vinson & Elkins L.L.P. has opined or will opine is "qualifying income" within the meaning of Section 7704(d) of the Internal Revenue Code.

If we fail to meet the Qualifying Income Exception, other than a failure that is determined by the IRS to be inadvertent and that is cured within a reasonable time after discovery, we will be treated as if we had transferred all of our assets, subject to liabilities, to a newly formed corporation, on the first day of the year in which we fail to meet the Qualifying Income Exception, in return for stock in that corporation, and then distributed that stock to the unitholders in liquidation of their interests in us. This contribution and liquidation should be tax-free to unitholders and us so long as we, at that time, do not have liabilities in excess of the tax basis of our assets. Thereafter, we would be treated as a corporation for federal income tax purposes.

If we were taxable as a corporation in any taxable year, either as a result of a failure to meet the Qualifying Income Exception or otherwise, our items of income, gain, loss and deduction would be reflected only on our tax return rather than being passed through to the unitholders, and our net income would be taxed to us at corporate rates. In addition, any distribution made to a unitholder would be treated as either taxable dividend income, to the extent of our current or accumulated earnings and profits, or, in the absence of earnings and profits, a nontaxable return of capital, to the extent of the unitholder's tax basis in his common units, or taxable capital gain, after the unitholder's tax basis in his common units is reduced to zero. Accordingly, taxation as a corporation would result in a material reduction in a unitholder's cash flow and after-tax return and thus would likely result in a substantial reduction of the value of the units.

The discussion below is based on Vinson & Elkins L.L.P.'s opinion that we will be classified as a partnership for federal income tax purposes.

Limited Partner Status

Unitholders who have become limited partners of Hiland Partners, LP will be treated as partners of Hiland Partners, LP for federal income tax purposes. Also, unitholders whose common units are held in street name or by a nominee and who have the right to direct the nominee in the exercise of all substantive rights attendant to the ownership of their common units will be treated as partners of Hiland Partners, LP for federal income tax purposes.

A beneficial owner of common units whose units have been transferred to a short seller to complete a short sale would appear to lose his status as a partner with respect to those units for federal income tax purposes. Please read " Tax Consequences of Unit Ownership Treatment of Short Sales."

Income, gain, deductions or losses would not be reportable by a unitholder who is not a partner for federal income tax purposes, and any cash distributions received by a unitholder who is not a partner for federal income tax purposes would therefore appear to be fully taxable as ordinary income. These holders are urged to consult their own tax advisors with respect to their tax consequences of holding common units in Hiland Partners, LP.

The references to "unitholders" in the discussion that follows are to persons who are treated as partners in Hiland Partners, LP for federal income tax purposes.

Tax Consequences of Unit Ownership

Flow-Through of Taxable Income. We will not pay any federal income tax. Instead, each unitholder will be required to report on his income tax return his share of our income, gains, losses and deductions without regard to whether corresponding cash distributions are received by him. Consequently, we may allocate income to a unitholder even if he has not received a cash distribution. Each unitholder will be required to include in income his allocable share of our income, gains, losses and deductions for our taxable year ending with or within his taxable year. Our taxable year ends on December 31.

Treatment of Distributions. Distributions by us to a unitholder generally will not be taxable to the unitholder for federal income tax purposes, except to the extent the amount of any such cash distribution exceeds his tax basis in his common units immediately before the distribution. Our cash distributions in excess of a unitholder's tax basis generally will be considered to be gain from the sale or exchange of the common units, taxable in accordance with the rules described under " Disposition of Common Units." Any reduction in a unitholder's share of our liabilities for which no partner, including the general partner, bears the economic risk of loss, known as "nonrecourse liabilities," will be treated as a distribution of cash to that unitholder. To the extent our distributions cause a unitholder's "at risk" amount to be less than zero at the end of any taxable year, he must recapture any losses deducted in previous years. Please read " Limitations on Deductibility of Losses."

A decrease in a unitholder's percentage interest in us because of our issuance of additional common units will decrease his share of our nonrecourse liabilities, and thus will result in a corresponding deemed distribution of cash. A non-pro rata distribution of money or property may result in ordinary income to a unitholder, regardless of his tax basis in his common units, if the distribution reduces the unitholder's share of our "unrealized receivables," including depreciation recapture, and/or substantially appreciated "inventory items," both as defined in the Internal Revenue Code, and collectively, "Section 751 Assets." To that extent, he will be treated as having been distributed his proportionate share of the Section 751 Assets and having exchanged those assets with us in return for the non-pro rata portion of the actual distribution made to him. This latter deemed exchange will generally result in the unitholder's realization of ordinary income, which will equal the excess of (1) the non-pro rata portion of that distribution over (2) the unitholder's tax basis for the share of Section 751 Assets deemed relinquished in the exchange.

Ratio of Taxable Income to Distributions. We estimate that a purchaser of common units in this offering who owns those common units from the date of closing of this offering through the record date for distributions for the period ending December 31, 2008, will be allocated an amount of federal taxable income for that period that will be 20% or less of the cash distributed with respect to that period. We anticipate that after the taxable year ending December 31, 2008, the ratio of allocable taxable income to cash distributions to the unitholders will increase. These estimates are based upon the assumption that gross income from operations will approximate the amount required to make the minimum quarterly distribution on all units and other assumptions with respect to capital expenditures, cash flow, net working capital and anticipated cash distributions. These estimates and assumptions are subject to, among other things, numerous business, economic, regulatory, competitive and political uncertainties beyond our control. Further, the estimates are based on current tax law and tax reporting positions that we will adopt and with which the IRS could disagree. Accordingly, we cannot assure you that these estimates will prove to be correct. The actual percentage of distributions that will constitute taxable income could be higher or lower, and any differences could be material and could materially affect the value of the common units.

Basis of Common Units. A unitholder's initial tax basis for his common units will be the amount he paid for the common units plus his share of our nonrecourse liabilities. That basis will be increased by his share of our income and by any increases in his share of our nonrecourse liabilities. That basis will be decreased, but not below zero, by distributions from us, by the unitholder's share of our losses, by any decreases in his share of our nonrecourse liabilities and by his share of our expenditures that are not deductible in computing taxable income and are not required to be capitalized. A unitholder will have no share of our debt that is recourse to the general partner, but will have a share, generally based on his share of profits, of our nonrecourse liabilities. Please read " Disposition of Common Units Recognition of Gain or Loss."

Limitations on Deductibility of Losses. The deduction by a unitholder of his share of our losses will be limited to the tax basis in his units and, in the case of an individual unitholder or a corporate unitholder, if more than 50% of the value of the corporate unitholder's stock is owned directly or indirectly by five or fewer individuals or some tax-exempt organizations, to the amount for which the unitholder is considered to be "at risk" with respect to our activities, if that is less than his tax basis. A unitholder must recapture losses deducted in previous years to the extent that distributions cause his at risk amount to be less than zero at the end of any taxable year. Losses disallowed to a unitholder or recaptured as a result of these limitations will carry forward and will be allowable to the extent that his tax basis or at risk amount, whichever is the limiting factor, is subsequently increased. Upon the taxable disposition of a unit, any gain recognized by a unitholder can be offset by losses that were previously suspended by the at risk limitation but may not be offset by losses suspended by the basis limitation. Any excess loss above that gain previously suspended by the at risk or basis limitations is no longer utilizable.

In general, a unitholder will be at risk to the extent of the tax basis of his units, excluding any portion of that basis attributable to his share of our nonrecourse liabilities, reduced by any amount of money he borrows to acquire or hold his units, if the lender of those borrowed funds owns an interest in us, is related to the unitholder or can look only to the units for repayment. A unitholder's at risk amount will increase or decrease as the tax basis of the unitholder's units increases or decreases, other than tax basis increases or decreases attributable to increases or decreases in his share of our nonrecourse liabilities.

The passive loss limitations generally provide that individuals, estates, trusts and some closely-held corporations and personal service corporations can deduct losses from passive activities, which are generally corporate or partnership activities in which the taxpayer does not materially participate, only to the extent of the taxpayer's income from those passive activities. The passive loss limitations are applied separately with respect to each publicly traded partnership. Consequently, any passive losses we generate will only be available to offset our passive income generated in the future and will not be available to offset income from other passive activities or investments, including our investments or investments in other publicly traded partnerships, or salary or active business income. Passive losses that are not deductible because they exceed a unitholder's share of income we generate may be deducted in full when he disposes of his entire investment in us in a fully taxable transaction with an unrelated party. The passive activity loss rules are applied after other applicable limitations on deductions, including the at risk rules and the basis limitation.

A unitholder's share of our net income may be offset by any of our suspended passive losses, but it may not be offset by any other current or carryover losses from other passive activities, including those attributable to other publicly traded partnerships.

Limitations on Interest Deductions. The deductibility of a non-corporate taxpayer's "investment interest expense" is generally limited to the amount of that taxpayer's "net investment income." Investment interest expense includes:

- interest on indebtedness properly allocable to property held for investment;
- our interest expense attributed to portfolio income; and
- the portion of interest expense incurred to purchase or carry an interest in a passive activity to the extent attributable to portfolio income.

The computation of a unitholder's investment interest expense will take into account interest on any margin account borrowing or other loan incurred to purchase or carry a unit. Net investment income includes gross income from property held for investment and amounts treated as portfolio income under the passive loss rules, less deductible expenses, other than interest, directly connected with the production of investment income, but generally does not include gains attributable to the disposition of property held for investment. The IRS has indicated that net passive income earned by a publicly traded partnership will be treated as investment income to its unitholders. In addition, the unitholder's share of our portfolio income will be treated as investment income.

Entity Level Collections. If we are required or elect under applicable law to pay any federal, state, local or foreign income tax on behalf of any unitholder or the general partner or any former unitholder, we are authorized to pay those taxes from our funds. That payment, if made, will be treated as a distribution of cash to the partner on whose behalf the payment was made. If the payment is made on behalf of a person whose identity cannot be determined, we are authorized to treat the payment as a distribution to all current unitholders. We are authorized to amend the partnership agreement in the manner necessary to maintain uniformity of intrinsic tax characteristics of units and to adjust later distributions, so that after giving effect to these distributions, the priority and characterization of distributions otherwise applicable under the partnership agreement is maintained as nearly as is practicable. Payments by us as described above could give rise to an overpayment of tax on behalf of an individual partner in which event the partner would be required to file a claim in order to obtain a credit or refund.

Allocation of Income, Gain, Loss and Deduction. In general, if we have a net profit, our items of income, gain, loss and deduction will be allocated among the general partner and the unitholders in accordance with their percentage interests in us. At any time that distributions are made to the common units in excess of distributions to the subordinated units, or incentive distributions are made to the general partner, gross income will be allocated to the recipients to the extent of these distributions. If we have a net loss for the entire year, that loss will be allocated first to the general partner and the unitholders in accordance with their percentage interests in us to the extent of their positive capital accounts and, second, to the general partner.

Specified items of our income, gain, loss and deduction will be allocated to account for the difference between the tax basis and fair market value of property contributed to us by the general partner and its affiliates, referred to in this discussion as "Contributed Property." The effect of these allocations to a unitholder purchasing common units in this offering will be essentially the same as if the tax basis of our assets were equal to their fair market value at the time of this offering. In addition, items of recapture income will be allocated to the extent possible to the partner who was allocated the deduction giving rise to the treatment of that gain as recapture income in order to minimize the recognition of ordinary income by some unitholders. Finally, although we do not expect that our operations will result in the creation of negative capital accounts, if negative capital accounts nevertheless result, items of our income and gain will be allocated in such amount and manner as is needed to eliminate the negative balance as quickly as possible.

An allocation of items of our income, gain, loss or deduction, other than an allocation required by the Internal Revenue Code to eliminate the difference between a partner's "book" capital account, credited with the fair market value of Contributed Property, and "tax" capital account, credited with the tax basis of Contributed Property, referred to in this discussion as the "Book-Tax Disparity," will generally be given effect for federal income tax purposes in determining a partner's share of an item of income, gain, loss or deduction only if the allocation has substantial economic effect.

Vinson & Elkins L.L.P. is of the opinion that, with the exception of the issues described in " Tax Consequences of Unit Ownership Section 754 Election" and " Disposition of Common Units Allocations Between Transferors and Transferees," allocations under our partnership agreement will be given effect for federal income tax purposes in determining a partner's share of an item of income, gain, loss or deduction.

Treatment of Short Sales. A unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition. As a result, during this period:

- any of our income, gain, loss or deduction with respect to those units would not be reportable by the unitholder;
- any cash distributions received by the unitholder as to those units would be fully taxable; and
- all of these distributions would appear to be ordinary income.

Vinson & Elkins L.L.P. has not rendered an opinion regarding the treatment of a unitholder where common units are loaned to a short seller to cover a short sale of common units; therefore, unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units. The IRS has announced that it is actively studying issues relating to the tax treatment of short sales of partnership interests. Please also read " Disposition of Common Units Recognition of Gain or Loss."

Alternative Minimum Tax. Each unitholder will be required to take into account his distributive share of any items of our income, gain, loss or deduction for purposes of the alternative minimum tax. The current minimum tax rate for noncorporate taxpayers is 26% on the first $175,000 of alternative minimum taxable income in excess of the exemption amount and 28% on any additional alternative minimum taxable income. Prospective unitholders are urged to consult with their tax advisors as to the impact of an investment in units on their liability for the alternative minimum tax.

Tax Rates. In general, the highest effective United States federal income tax rate for individuals is currently 35.0% and the maximum United States federal income tax rate for net capital gains of an individual is currently 15.0% if the asset disposed of was held for more than 12 months at the time of disposition.

Section 754 Election. We will make the election permitted by Section 754 of the Internal Revenue Code. That election is irrevocable without the consent of the IRS. The election will generally permit us to adjust a common unit purchaser's tax basis in our assets ("inside basis") under Section 743(b) of the Internal Revenue Code to reflect his purchase price. This election does not apply to a person who purchases common units directly from us. The Section 743(b) adjustment belongs to the purchaser and not to other unitholders. For purposes of this discussion, a unitholder's inside basis in our assets will be considered to have two components: (1) his share of our tax basis in our assets ("common basis") and (2) his Section 743(b) adjustment to that basis.

Where the remedial allocation method is adopted (which we will adopt), Treasury Regulations under Section 743 of the Internal Revenue Code require a portion of the Section 743(b) adjustment that is attributable to recovery property to be depreciated over the remaining cost recovery period for the Section 704(c) built-in gain. Under Treasury Regulation Section 1.167(c)-1(a)(6), a Section 743(b) adjustment attributable to property subject to depreciation under Section 167 of the Internal Revenue Code, rather than cost recovery deductions under Section 168, is generally required to be depreciated using either the straight-line method or the 150% declining balance method. Under our partnership agreement, the general partner is authorized to take a position to preserve the uniformity of units even if that position is not consistent with these Treasury Regulations. Please read " Uniformity of Units."

Although Vinson & Elkins L.L.P. is unable to opine as to the validity of this approach because there is no controlling authority on this issue, we intend to depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of Contributed Property, to the extent of any unamortized Book-Tax Disparity, using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the common basis of the property, or treat that portion as non-amortizable to the extent attributable to property the common basis of which is not amortizable. This method is consistent with the regulations under Section 743 of the Internal Revenue Code but is arguably inconsistent with Treasury Regulation Section 1.167(c)-1(a)(6), which is not expected to directly apply to a material portion of our assets. To the extent this Section 743(b) adjustment is attributable to appreciation in value in excess of the unamortized Book-Tax Disparity, we will apply the rules described in the Treasury Regulations and legislative history. If we determine that this position cannot reasonably be taken, we may take a depreciation or amortization position under which all purchasers acquiring units in the same month would receive depreciation or amortization, whether attributable to common basis or a Section 743(b) adjustment, based upon the same applicable rate as if they had purchased a direct interest in our assets. This kind of aggregate approach may result in lower annual depreciation or amortization deductions than would otherwise be allowable to some unitholders. Please read " Uniformity of Units."

A Section 754 election is advantageous if the transferee's tax basis in his units is higher than the units' share of the aggregate tax basis of our assets immediately prior to the transfer. In that case, as a result of the election, the transferee would have, among other items, a greater amount of depreciation and depletion deductions and his share of any gain or loss on a sale of our assets would be less.

The calculations involved in the Section 754 election are complex and will be made on the basis of assumptions as to the value of our assets and other matters. For example, the allocation of the Section 743(b) adjustment among our assets must be made in accordance with the Internal Revenue Code. The IRS could seek to reallocate some or all of any Section 743(b) adjustment allocated by us to our tangible assets to goodwill instead. Goodwill, as an intangible asset, is generally amortizable over a longer period of time or under a less accelerated method than our tangible assets. We cannot assure you that the determinations we make will not be successfully challenged by the IRS and that the deductions resulting from them will not be reduced or disallowed altogether. Should the IRS require a different basis adjustment to be made, and should, in our opinion, the expense of compliance exceed the benefit of the election, we may seek permission from the IRS to revoke our Section 754 election. If permission is granted, a subsequent purchaser of units may be allocated more income than he would have been allocated had the election not been revoked.

Tax Treatment of Operations

Accounting Method and Taxable Year. We use the year ending December 31 as our taxable year and the accrual method of accounting for federal income tax purposes. Each unitholder will be required to include in income his share of our income, gain, loss and deduction for our taxable year ending within or with his taxable year. In addition, a unitholder who has a taxable year ending on a date other than December 31 and who disposes of all of his units following the close of our taxable year but before the close of his taxable year must include his share of our income, gain, loss and deduction in income for his taxable year, with the result that he will be required to include in income for his taxable year his share of more than one year of our income, gain, loss and deduction. Please read " Disposition of Common Units Allocations Between Transferors and Transferees."

Initial Tax Basis, Depreciation and Amortization. The tax basis of our assets will be used for purposes of computing depreciation and cost recovery deductions and, ultimately, gain or loss on the disposition of these assets. The federal income tax burden associated with the difference between the fair market value of our assets and their tax basis immediately prior to this offering will be borne by the general partner and our current unitholders. Please read " Tax Consequences of Unit Ownership Allocation of Income, Gain, Loss and Deduction."

To the extent allowable, we may elect to use the depreciation and cost recovery methods that will result in the largest deductions being taken in the early years after assets are placed in service. We are not entitled to any amortization deductions with respect to any goodwill conveyed to us on formation. Property we subsequently acquire or construct may be depreciated using accelerated methods permitted by the Internal Revenue Code.

If we dispose of depreciable property by sale, foreclosure or otherwise, all or a portion of any gain, determined by reference to the amount of depreciation previously deducted and the nature of the property, may be subject to the recapture rules and taxed as ordinary income rather than capital gain. Similarly, a unitholder who has taken cost recovery or depreciation deductions with respect to property we own will likely be required to recapture some or all of those deductions as ordinary income upon a sale of his interest in us. Please read " Tax Consequences of Unit Ownership Allocation of Income, Gain, Loss and Deduction" and " Disposition of Common Units Recognition of Gain or Loss."

The costs incurred in selling our units (called "syndication expenses") must be capitalized and cannot be deducted currently, ratably or upon our termination. There are uncertainties regarding the classification of costs as organization expenses, which may be amortized by us, and as syndication expenses, which may not be amortized by us. The underwriting discounts and commissions we incur will be treated as syndication expenses.

Valuation and Tax Basis of Our Properties. The federal income tax consequences of the ownership and disposition of units will depend in part on our estimates of the relative fair market values, and the initial tax bases, of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we will make many of the relative fair market value estimates ourselves. These estimates and determinations of basis are subject to challenge and will not be binding on the IRS or the courts. If the estimates of fair market value or basis are later found to be incorrect, the character and amount of items of income, gain, loss or deductions previously reported by unitholders might change, and unitholders might be required to adjust their tax liability for prior years and incur interest and penalties with respect to those adjustments.

Disposition of Common Units

Recognition of Gain or Loss. Gain or loss will be recognized on a sale of units equal to the difference between the amount realized and the unitholder's tax basis for the units sold. A unitholder's amount realized will be measured by the sum of the cash or the fair market value of other property received by him plus his share of our nonrecourse liabilities. Because the amount realized includes a unitholder's share of our nonrecourse liabilities, the gain recognized on the sale of units could result in a tax liability in excess of any cash received from the sale.

Prior distributions from us in excess of cumulative net taxable income for a common unit that decreased a unitholder's tax basis in that common unit will, in effect, become taxable income if the common unit is sold at a price greater than the unitholder's tax basis in that common unit, even if the price received is less than his original cost.

Except as noted below, gain or loss recognized by a unitholder, other than a "dealer" in units, on the sale or exchange of a unit held for more than one year will generally be taxable as capital gain or loss. Capital gain recognized by an individual on the sale of units held more than 12 months is currently generally taxed at a maximum rate of 15%. However, a portion of this gain or loss will be separately computed and taxed as ordinary income or loss under Section 751 of the Internal Revenue Code to the extent attributable to assets giving rise to depreciation recapture or other "unrealized receivables" or to "inventory items" we own. The term "unrealized receivables" includes potential recapture items, including depreciation recapture. Ordinary income attributable to unrealized receivables, inventory items and depreciation recapture may exceed net taxable gain realized upon the sale of a unit and may be recognized even if there is a net taxable loss realized on the sale of a unit. Thus, a unitholder may recognize both ordinary income and a capital loss upon a sale of units. Net capital losses may offset capital gains and no more than $3,000 of ordinary income, in the case of individuals, and may only be used to offset capital gains in the case of corporations.

The IRS has ruled that a partner who acquires interests in a partnership in separate transactions must combine those interests and maintain a single adjusted tax basis for all those interests. Upon a sale or other disposition of less than all of those interests, a portion of that tax basis must be allocated to the interests sold using an "equitable apportionment" method, which generally means that the tax basis allocated to the interest sold equals an amount that bears the same relation to the partner's tax basis in his entire interest in the partnership as the value of the interest sold bears to the value of the partner's entire interest in the partnership. Treasury Regulations under Section 1223 of the Internal Revenue Code allow a selling unitholder who can identify common units transferred with an ascertainable holding period to elect to use the actual holding period of the common units transferred. Thus, according to the ruling, a common unitholder will be unable to select high or low basis common units to sell as would be the case with corporate stock, but, according to the regulations, may designate specific common units sold for purposes of determining the holding period of units transferred. A unitholder electing to use the actual holding period of common units transferred must consistently use that identification method for all subsequent sales or exchanges of common units. A unitholder considering the purchase of additional units or a sale of common units purchased in separate transactions is urged to consult his tax advisor as to the possible consequences of this ruling and application of the regulations.

Specific provisions of the Internal Revenue Code affect the taxation of some financial products and securities, including partnership interests, by treating a taxpayer as having sold an "appreciated" partnership interest, one in which gain would be recognized if it were sold, assigned or terminated at its fair market value, if the taxpayer or related persons enter(s) into:

- a short sale;
- an offsetting notional principal contract; or
- a futures or forward contract with respect to the partnership interest or substantially identical property.

Moreover, if a taxpayer has previously entered into a short sale, an offsetting notional principal contract or a futures or forward contract with respect to the partnership interest, the taxpayer will be treated as having sold that position if the taxpayer or a related person then acquires the partnership interest or substantially identical property. The Secretary of the Treasury is also authorized to issue regulations that treat a taxpayer that enters into transactions or positions that have substantially the same effect as the preceding transactions as having constructively sold the financial position.

Allocations Between Transferors and Transferees. In general, our taxable income and losses will be determined annually, will be prorated on a monthly basis and will be subsequently apportioned among the unitholders in proportion to the number of units owned by each of them as of the opening of the applicable exchange on the first business day of the month, which we refer to in this prospectus as the "Allocation Date." However, gain or loss realized on a sale or other disposition of our assets other than in the ordinary course of business will be allocated among the unitholders on the Allocation Date in the month in which that gain or loss is recognized. As a result, a unitholder transferring units may be allocated income, gain, loss and deduction realized after the date of transfer.

The use of this method may not be permitted under existing Treasury Regulations as there is no controlling authority on the issue. Accordingly, Vinson & Elkins L.L.P. is unable to opine on the validity of this method of allocating income and deductions between unitholders although Vinson & Elkins L.L.P. is of the opinion that this method is a reasonable method. If this method is not allowed under the Treasury Regulations, or only applies to transfers of less than all of the unitholder's interest, our taxable income or losses might be reallocated among the unitholders. We are authorized to revise our method of allocation between unitholders, as well as unitholders whose interests vary during a taxable year, to conform to a method permitted under future Treasury Regulations.

A unitholder who owns units at any time during a quarter and who disposes of them prior to the record date set for a cash distribution for that quarter will be allocated items of our income, gain, loss and deductions attributable to that quarter but will not be entitled to receive that cash distribution.

Notification Requirements. A unitholder who sells any of his units, other than through a broker, generally is required to notify us in writing of that sale within 30 days after the sale (or, if earlier, January 15 of the year following the sale). A purchaser of units who purchases units from another unitholder generally is required to notify us in writing of that purchase within 30 days after the purchase, unless a broker or nominee will satisfy such requirement. We are required to notify the IRS of that transaction and to furnish specified information to the transferor and transferee. Failure to notify us of a purchase may lead, in some cases, to the imposition of penalties. However, these reporting requirements do not apply to a sale by an individual who is a citizen of the United States and who effects the sale or exchange through a broker.

Constructive Termination. We will be considered to have been 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 12-month period. A constructive termination results in the closing of our taxable year for all unitholders. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may result in more than 12 months of our taxable income or loss being includable in his taxable income for the year of termination. We would be required to make new tax elections after a termination, including a new election under Section 754 of the Internal Revenue Code, and a termination would result in a deferral of our deductions for depreciation. A termination could also result in penalties if we were unable to determine that the termination had occurred. Moreover, a termination might either accelerate the application of, or subject us to, any tax legislation enacted before the termination.

Uniformity of Units

Because we cannot match transferors and transferees of units, we must maintain uniformity of the economic and tax characteristics of the units to a purchaser of these units. In the absence of uniformity, we may be unable to completely comply with a number of federal income tax requirements, both statutory and regulatory. A lack of uniformity can result from a literal application of Treasury Regulation Section 1.167(c)-1(a)(6). Any non-uniformity could have a negative impact on the value of the units. Please read " Tax Consequences of Unit Ownership Section 754 Election."

We intend to depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of Contributed Property, to the extent of any unamortized Book-Tax Disparity, using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the common basis of that property, or treat that portion as nonamortizable, to the extent attributable to property the common basis of which is not amortizable, consistent with the regulations under Section 743 of the Internal Revenue Code, even though that position may be inconsistent with Treasury Regulation Section 1.167(c)-1(a)(6), which is not expected to directly apply to a material portion of our assets. Please read " Tax Consequences of Unit Ownership Section 754 Election." To the extent that the Section 743(b) adjustment is attributable to appreciation in value in excess of the unamortized Book-Tax Disparity, we will apply the rules described in the Treasury Regulations and legislative history. If we determine that this position cannot reasonably be taken, we may adopt a depreciation and amortization position under which all purchasers acquiring units in the same month would receive depreciation and amortization deductions, whether attributable to a common basis or Section 743(b) adjustment, based upon the same applicable rate as if they had purchased a direct interest in our property. If this position is adopted, it may result in lower annual depreciation and amortization deductions than would otherwise be allowable to some unitholders and risk the loss of depreciation and amortization deductions not taken in the year that these deductions are otherwise allowable. This position will not be adopted if we determine that the loss of depreciation and amortization deductions will have a material adverse effect on the unitholders. If we choose not to utilize this aggregate method, we may use any other reasonable depreciation and amortization method to preserve the uniformity of the intrinsic tax characteristics of any units that would not have a material adverse effect on the unitholders. The IRS may challenge any method of depreciating the Section 743(b) adjustment described in this paragraph. If this challenge were sustained, the uniformity of units might be affected, and the gain from the sale of units might be increased without the benefit of additional deductions. Please read " Disposition of Common Units Recognition of Gain or Loss."

Tax-Exempt Organizations and Other Investors

Ownership of units by employee benefit plans, other tax-exempt organizations, non-resident aliens, foreign corporations and other foreign persons raises issues unique to those investors and, as described below, may have substantially adverse tax consequences to them.

Employee benefit plans and most other organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, are subject to federal income tax on unrelated business taxable income. Virtually all of our income allocated to a unitholder that is a tax-exempt organization will be unrelated business taxable income and will be taxable to them.

Non-resident aliens and foreign corporations, trusts or estates that own units will be considered to be engaged in business in the United States because of the ownership of units. As a consequence, they will be required to file federal tax returns to report their share of our income, gain, loss or deduction and pay federal income tax at regular rates on their share of our net income or gain. Moreover, under rules applicable to publicly traded partnerships, we will withhold at the highest applicable effective tax rate from cash distributions made quarterly to foreign unitholders. Each foreign unitholder must obtain a taxpayer identification number from the IRS and submit that number to our transfer agent on a Form W-8BEN or applicable substitute form in order to obtain credit for these withholding taxes. A change in applicable law may require us to change these procedures.

In addition, because a foreign corporation that owns units will be treated as engaged in a United States trade or business, that corporation may be subject to the United States branch profits tax at a rate of 30%, in addition to regular federal income tax, on its share of our income and gain, as adjusted for changes in the foreign corporation's "U.S. net equity," which are effectively connected with the conduct of a United States trade or business. That tax may be reduced or eliminated by an income tax treaty between the United States and the country in which the foreign corporate unitholder is a "qualified resident." In addition, this type of unitholder is subject to special information reporting requirements under Section 6038C of the Internal Revenue Code.

Under a published ruling of the IRS, the IRS has taken the position that a foreign unitholder who sells or otherwise disposes of a unit will be subject to federal income tax on gain realized on the sale or disposition of that unit to the extent the gain is attributable to appreciated property, other than United States real property interests, that is effectively connected with a United States trade or business of the partnership. Moreover, a foreign unitholder is subject to federal income tax on gain realized on the sale or disposition of a unit to the extent that such gain is attributable to appreciated United States real property interests; however, a foreign unitholder will not be subject to federal income tax under this rule unless such foreign unitholder has owned more than 5% in value of our units during the five-year period ending on the date of the sale or disposition, provided the units are regularly traded on an established securities market at the time of the sale or disposition.

Administrative Matters

Information Returns and Audit Procedures. We intend to furnish to each unitholder, within 90 days after the close of each calendar year, specific tax information, including a Schedule K-1, which describes his share of our income, gain, loss and deduction for our preceding taxable year. In preparing this information, which will not be reviewed by counsel, we will take various accounting and reporting positions, some of which have been mentioned earlier, to determine each unitholder's share of income, gain, loss and deduction. We cannot assure you that those positions will in all cases yield a result that conforms to the requirements of the Internal Revenue Code, Treasury Regulations or administrative interpretations of the IRS. Neither we nor Vinson & Elkins L.L.P. can assure prospective unitholders that the IRS will not successfully contend in court that those positions are impermissible. Any challenge by the IRS could negatively affect the value of the units.

The IRS may audit our federal income tax information returns. Adjustments resulting from an IRS audit may require each unitholder to adjust a prior year's tax liability, and possibly may result in an audit of his return. Any audit of a unitholder's return could result in adjustments not related to our returns as well as those related to our returns.

Partnerships generally are treated as separate entities for purposes of federal tax audits, judicial review of administrative adjustments by the IRS and tax settlement proceedings. The tax treatment of partnership items of income, gain, loss and deduction are determined in a partnership proceeding rather than in separate proceedings with the partners. The Internal Revenue Code requires that one partner be designated as the "Tax Matters Partner" for these purposes. The partnership agreement names Hiland Partners GP, LLC as our Tax Matters Partner.

The Tax Matters Partner will make some elections on our behalf and on behalf of unitholders. In addition, the Tax Matters Partner can extend the statute of limitations for assessment of tax deficiencies against unitholders for items in our returns. The Tax Matters Partner may bind a unitholder with less than a 1% profits interest in us to a settlement with the IRS unless that unitholder elects, by filing a statement with the IRS, not to give that authority to the Tax Matters Partner. The Tax Matters Partner may seek judicial review, by which all the unitholders are bound, of a final partnership administrative adjustment and, if the Tax Matters Partner fails to seek judicial review, judicial review may be sought by any unitholder having at least a 1% interest in profits or by any group of unitholders having in the aggregate at least a 5% interest in profits. However, only one action for judicial review will go forward, and each unitholder with an interest in the outcome may participate.

A unitholder must file a statement with the IRS identifying the treatment of any item on his federal income tax return that is not consistent with the treatment of the item on our return. Intentional or negligent disregard of this consistency requirement may subject a unitholder to substantial penalties.

Nominee Reporting. Persons who hold an interest in us as a nominee for another person are required to furnish to us:

(a) the name, address and taxpayer identification number of the beneficial owner and the nominee;

(b) whether the beneficial owner is:

1. a person that is not a United States person;
2. a foreign government, an international organization or any wholly owned agency or instrumentality of either of the foregoing; or
3. a tax-exempt entity;

(c) the amount and description of units held, acquired or transferred for the beneficial owner; and

(d) specific information including the dates of acquisitions and transfers, means of acquisitions and transfers, and acquisition cost for purchases, as well as the amount of net proceeds from sales.

Brokers and financial institutions are required to furnish additional information, including whether they are United States persons and specific information on units they acquire, hold or transfer for their own account. A penalty of $50 per failure, up to a maximum of $100,000 per calendar year, is imposed by the Internal Revenue Code for failure to report that information to us. The nominee is required to supply the beneficial owner of the units with the information furnished to us.

Accuracy Related Penalties. An additional tax equal to 20% of the amount of any portion of an underpayment of tax that is attributable to one or more specified causes, including negligence or disregard of rules or regulations, substantial understatements of income tax and substantial valuation misstatements, is imposed by the Internal Revenue Code. No penalty will be imposed, however, for any portion of an underpayment if it is shown that there was a reasonable cause for that portion and that the taxpayer acted in good faith regarding that portion.

For individuals, a substantial understatement of income tax in any taxable year exists if the amount of the understatement exceeds the greater of 10% of the tax required to be shown on the return for the taxable year or $5,000. The amount of any understatement subject to penalty generally is reduced if any portion is attributable to a position adopted on the return:

(1) for which there is, or was, "substantial authority;" or

(2) as to which there is a reasonable basis and the pertinent facts of that position are disclosed on the return.

If any item of income, gain, loss or deduction included in the distributive shares of unitholders might result in that kind of an "understatement" of income for which no "substantial authority" exists, we must disclose the pertinent facts on our return. In addition, we will make a reasonable effort to furnish sufficient information for unitholders to make adequate disclosure on their returns and to take other actions as may be appropriate to permit unitholders to avoid liability for penalties. More stringent rules apply to "tax shelters," which we do not believe includes us.

A substantial valuation misstatement exists if the value of any property, or the adjusted basis of any property, claimed on a tax return is 200% or more of the amount determined to be the correct amount of the valuation or adjusted basis. No penalty is imposed unless the portion of the underpayment attributable to a substantial valuation misstatement exceeds $5,000 ($10,000 for most corporations). If the valuation claimed on a return is 400% or more than the correct valuation, the penalty imposed increases to 40%.

Reportable Transactions. If we were to engage in a "reportable transaction," we (and possibly you and others) would be required to make a detailed disclosure of the transaction to the IRS. A transaction may be a reportable transaction based upon any of several factors, including the fact that it is a type of tax avoidance transaction publicly identified by the IRS as a "listed transaction" or that it produces certain kinds of losses in excess of $2 million. Our participation in a reportable transaction could increase the likelihood that our federal income tax information return (and possibly your tax return) would be audited by the IRS. Please read " Information Returns and Audit Procedures."

Moreover, if we were to participate in a reportable transaction with a significant purpose to avoid or evade tax, or in any listed transaction, you may be subject to the following provisions of the American Jobs Creation Act of 2004:

- accuracy-related penalties with a broader scope, significantly narrower exceptions, and potentially greater amounts than described above at " Accuracy-related Penalties,"
- for those persons otherwise entitled to deduct interest on federal tax deficiencies, nondeductibility of interest on any resulting tax liability and
- in the case of a listed transaction, an extended statute of limitations.

We do not expect to engage in any "reportable transactions"

State, Local, Foreign and Other Tax Considerations

In addition to federal income taxes, you likely will be subject to other taxes, such as state, local and foreign income taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that may be imposed by the various jurisdictions in which we do business or own property or in which you are a resident. Although an analysis of those various taxes is not presented here, each prospective unitholder should consider their potential impact on his investment in us. We own property or do business in Oklahoma, North Dakota, Wyoming, Texas, Montana and Mississippi. Mississippi, North Dakota, Montana and Oklahoma each impose a personal income tax on individuals as well as an income tax on corporations and other entities. We may also own property or do business in other jurisdictions in the future. Although you may not be required to file a return and pay taxes in some jurisdictions because your income from that jurisdiction falls below the filing and payment requirement, you will be required to file income tax returns and to pay income taxes in many of these jurisdictions in which we do business or own property and may be subject to penalties for failure to comply with those requirements. In some jurisdictions, tax losses may not produce a tax benefit in the year incurred and may not be available to offset income in subsequent taxable years. Some of the jurisdictions may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the jurisdiction. Withholding, the amount of which may be greater or less than a particular unitholder's income tax liability to the jurisdiction, generally does not relieve a nonresident unitholder from the obligation to file an income tax return. Amounts withheld will be treated as if distributed to unitholders for purposes of determining the amounts distributed by us. Please read " Tax Consequences of Unit Ownership Entity Level Collections." Based on current law and our estimate of our future operations, the general partner anticipates that any amounts required to be withheld will not be material.

It is the responsibility of each unitholder to investigate the legal and tax consequences, under the laws of pertinent jurisdictions, of his investment in us. Accordingly, each prospective unitholder is urged to consult, and depend upon, his tax counsel or other advisor with regard to those matters. Further, it is the responsibility of each unitholder to file all state, local and foreign, as well as United States federal tax returns, that may be required of him. Vinson & Elkins L.L.P. has not rendered an opinion on the state, local or foreign tax consequences of an investment in us.

INVESTMENT IN HILAND PARTNERS, LP BY EMPLOYEE BENEFIT PLANS

An investment in us by an employee benefit plan is subject to additional considerations because the investments of these plans are subject to the fiduciary responsibility and prohibited transaction provisions of ERISA and restrictions imposed by Section 4975 of the Internal Revenue Code. For these purposes the term "employee benefit plan" includes, but is not limited to, qualified pension, profit sharing and stock bonus plans, Keogh plans, simplified employee pension plans and tax deferred annuities or IRAs established or maintained by an employer or employee organization. Among other things, consideration should be given to:

- whether the investment is prudent under Section 404(a)(1)(B) of ERISA;
- whether in making the investment, that plan will satisfy the diversification requirements of Section 404(a)(1)(C) of ERISA; and
- whether the investment will result in recognition of unrelated business taxable income by the plan and, if so, the potential after-tax investment return.

The person with investment discretion with respect to the assets of an employee benefit plan, often called a fiduciary, should determine whether an investment in us is authorized by the appropriate governing instrument and is a proper investment for the plan.

Section 406 of ERISA and Section 4975 of the Internal Revenue Code prohibit employee benefit plans, and also IRAs that are not considered part of an employee benefit plan, from engaging in specified transactions involving "plan assets" with parties that are "parties in interest" under ERISA or "disqualified persons" under the Internal Revenue Code with respect to the plan.

In addition to considering whether the purchase of common units is a prohibited transaction, a fiduciary of an employee benefit plan should consider whether the plan will, by investing in us, be deemed to own an undivided interest in our assets, with the result that our operations would be subject to the regulatory restrictions of ERISA, including its prohibited transaction rules, as well as the prohibited transaction rules of the Internal Revenue Code.

The Department of Labor regulations provide guidance with respect to whether the assets of an entity in which employee benefit plans acquire equity interests would be deemed "plan assets" under some circumstances. Under these regulations, an entity's assets would not be considered to be "plan assets" if, among other things:

(a) the equity interests acquired by employee benefit plans are publicly offered securities i.e., the equity interests are widely held by 100 or more investors independent of the issuer and each other, freely transferable and registered under some provisions of the federal securities laws;

(b) the entity is an "operating company," i.e., it is primarily engaged in the production or sale of a product or service other than the investment of capital either directly or through a majority owned subsidiary or subsidiaries; or

(c) there is no significant investment by benefit plan investors, which is defined to mean that less than 25% of the value of each class of equity interest is held by the employee benefit plans referred to above, IRAs and other employee benefit plans not subject to ERISA, including governmental plans.

Our assets should not be considered "plan assets" under these regulations because it is expected that the investment will satisfy the requirements in (a) above.

Plan fiduciaries contemplating a purchase of common units should consult with their own counsel regarding the consequences under ERISA and the Internal Revenue Code in light of the serious penalties imposed on persons who engage in prohibited transactions or other violations.

UNDERWRITING

Subject to the terms and conditions of the underwriting agreement between us and the underwriters, the underwriters have agreed severally to purchase from us the following number of common units at the offering price less the underwriting discount set forth on the cover page of this prospectus.

Underwriters	Number of Common Units
A.G. Edwards & Sons, Inc.	720,000
Raymond James & Associates, Inc.	440,000
RBC Capital Markets Corporation	440,000
Total	1,600,000

The underwriting agreement provides that the obligations of the underwriters to purchase the common units depend on the satisfaction of the conditions contained in the underwriting agreement, which include:

- the representations and warranties made by us to the underwriters are true;
- there has been no material adverse change in our condition or in the financial markets; and
- we deliver to the underwriters customary closing documents.

The underwriters are obligated to take and pay for all of the common units offered by this prospectus, other than those covered by the over allotment option described below, if any are taken.

The underwriters have advised us that they propose to offer the common units to the public at the offering price set forth on the cover page of this prospectus and to certain dealers at such price less a concession not in excess of $1.21 per common unit. The underwriters may allow, and such dealers may re-allow, a concession not in excess of $0.10 per common unit to certain other dealers. After the offering, the offering price and other selling terms may be changed by the underwriters, but any such changes will not affect the net proceeds to be received by us in the offering.

Pursuant to the underwriting agreement, we have granted to the underwriters an option, exercisable in whole or in part for 30 days after the date of this prospectus, to purchase up to 240,000 additional common units at the offering price, less the underwriting discount set forth on the cover page of this prospectus, solely to cover over-allotments.

To the extent the underwriters exercise such option, the underwriters will become obligated, subject to certain conditions, to purchase approximately the same percentage of such additional units as the number set forth next to such underwriter's name in the preceding table bears to the total number of units in the table, and we will be obligated, pursuant to the option, to sell such units to the underwriters.

We, our general partner, the directors and executive officers of our general partner and certain of our affiliates, including the Hamm Parties, have agreed that during the 90 days after the date of this prospectus, we and they will not, without the prior written consent of A.G. Edwards & Sons, Inc., directly or indirectly, offer for sale, sell, pledge, grant any option, right or warrant with respect to, enter into any derivative transaction with similar effect as a sale or otherwise dispose of any common units, any securities convertible into or exchangeable for common units, other than in specified cases pursuant to employee benefit plans as in existence as of the date of this prospectus or pursuant to options, rights or warrants outstanding on the date of this prospectus.

A.G. Edwards & Sons, Inc. may, in its sole discretion, allow any of these parties to offer for sale, sell, pledge, grant any option, right or warrant with respect to, enter into any derivative transaction with similar effect as a sale or otherwise dispose of any common units, any securities convertible into or exchangeable for, common units or any other rights to acquire such common units prior to the expiration of such 90-day period in whole or in part at anytime without notice. A.G. Edwards & Sons, Inc. has informed us that in the event that consent to a waiver of these restrictions is requested by us or any other person, A.G. Edwards & Sons, Inc., in deciding whether to grant its consent, will consider the unitholder's reasons for requesting the release, the number of units for which the release is being requested and market conditions at the time of the request for such release. However, A.G. Edwards & Sons, Inc. has informed us that as of the date of this prospectus there are no agreements between A.G. Edwards & Sons, Inc. and any party that would allow such party to transfer any common units, nor does it have any intention of releasing any of the common units subject to the lock-up agreements prior to the expiration of the lock-up period at this time. The 90-day lock up period will be extended if:

- during the last 17 days of the 90 day period we issue an earnings release or material news or a material event relating to our partnership occurs; or

- prior to the expiration of the 90 day period, we announce that we will release earnings results during the 16 day period beginning on the last day of the 90 day period;

in which case the restrictions described in this paragraph will continue to apply until the expiration of the 18 day period beginning on the issuance of the earnings release or the occurrence of the material news or material event.

The following table summarizes the discounts that we will pay to the underwriters in connection with the offering. These amounts assume both no exercise and full exercise of the underwriters' option to purchase additional common units.

	No Exercise	Full Exercise
Per Unit	$ 2.088	$ 2.088
Total	$ 3,340,800	$ 3,841,920

We estimate that total expenses of this offering, other than underwriting discounts and commissions, will be approximately $675,000.

We, our general partner and the operating company have agreed to indemnify the underwriters against certain liabilities, including liabilities under the Securities Act, or to contribute to payments that may be required with respect to these liabilities.

Our common units are quoted on the Nasdaq National Market under the symbol "HLND."

Until the distribution of the common units is completed, rules of the SEC may limit the ability of the underwriters and certain selling group members to bid for and purchase the common units. As an exception to these rules, the underwriters are permitted to engage in certain transactions that stabilize, maintain or otherwise affect the price of the common units.

In connection with this offering, the underwriters may engage in stabilizing transactions, over-allotment transactions, syndicate covering transactions and penalty bids in accordance with Regulation M under the Securities Exchange Act of 1934.

- Stabilizing transactions permit bids to purchase the underlying security so long as the stabilizing bids do not exceed a specified maximum.

- Over-allotment transactions involve sales by the underwriters of the common units in excess of the number of units the underwriters are obligated to purchase, which creates a syndicate short position. The short position may be either a covered short position or a naked short position. In a covered short position, the number of units over-allotted by the underwriters is not greater than the number of units they may purchase in the over-allotment option. In a naked short position, the number of units involved is greater than the number of units in the over-allotment option. The underwriters may close out any short position by either exercising their over-allotment option and/or purchasing common units in the open market.

Syndicate covering transactions involve purchases of the common units in the open market after the distribution has been completed in order to cover syndicate short positions. In determining the source of the common units to close out the short position, the underwriters will consider, among other things, the price of common units available for purchase in the open market as compared to the price at which they may purchase common units through the over-allotment option. If the underwriters sell more common units than could be covered by the over-allotment option, resulting in a naked short position, the position can only be closed out by buying common units in the open market. A naked short position is more likely to be created if the underwriters are concerned that there could be downward pressure on the price of the common units in the open market after pricing that could adversely affect investors who purchase in the offering.

Penalty bids permit the representatives to reclaim a selling concession from a syndicate member when the common units originally sold by the syndicate member are purchased in a stabilizing or syndicate covering transaction to cover syndicate short positions.

Similar to other purchase transactions, the underwriters' purchases to cover the syndicate short sales may have the effect of raising or maintaining the market price of the common units or preventing or retarding a decline in the market price of the common units. As a result, the price of the common units may be higher than the price that might otherwise exist in the open market. These transactions may be effected on the NASDAQ National Market or otherwise.

The underwriters will deliver a prospectus to all purchasers of common units in the short sales. The purchasers of common units in short sales are entitled to the same remedies under the federal securities laws as any other purchaser of common units covered by this prospectus.

The underwriters are not obligated to engage in any of the transactions described above. If they do engage in any of these transactions, they may discontinue them at any time.

In addition, in connection with this offering, the underwriters (and selling group members) may engage in passive market making transactions in the common units on the Nasdaq National Market in accordance with Rule 103 of Regulation M under the Securities Exchange Act of 1934 during the period before the commencement of offers or sales of common units and extending through the completion of distribution. A passive market maker must display its bids at a price not in excess of the highest independent bid of the security. However, if all independent bids are lowered below the passive market maker's bid, that bid must be lowered when specified purchase limits are exceeded.

Neither we nor the underwriters make any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of the common units. In addition, neither we nor the underwriters make any representation that the underwriters will engage in these transactions or that these transactions, once commenced, will not be discontinued without notice.

A prospectus in electronic format may be made available on the Internet sites or through other online services maintained by the underwriters and/or selling group members participating in this common unit offering, or by their affiliates. In those cases, prospective investors may view offering terms online and, depending upon the particular underwriters or selling group members, prospective investors may be allowed to place orders online. The underwriters may agree with us to allocate a specific number of common units for sale to online brokerage account holders. Any such allocation for online distributions will be made by underwriters on the same basis as other allocations.

Other than the prospectus in electronic format, the information on the underwriters' or selling group members' website and any information contained in any other website maintained by the underwriters or selling group members is not part of the prospectus or the registration statement of which this prospectus forms a part, has not been approved and/or endorsed by us or the underwriters or selling group members in their capacity as underwriters or selling group members and should not be relied upon by investors.

Because the National Association of Securities Dealers, Inc. views the common units offered hereby as interests in a direct participation program, this offering is being made in compliance with Rule 2810 of the NASD's Conduct Rules. Investor suitability with respect to the common units should be judged similarly to the suitability with respect to other securities that are listed for trading on a national securities exchange.

No sales to accounts over which any underwriter exercises discretionary authority may be made without the prior written approval of the customer.

In no event will the maximum amount of compensation to be paid to NASD members in connection with this offering exceed 10% of the gross proceeds (plus 0.5% for bona fide, accountable due diligence expenses).

A.G. Edwards & Sons, Inc. has performed various financial advisory services for us and our predecessor for which it received customary compensation. In addition, each of the underwriters in this offering was an underwriter in our initial public offering that closed on February 15, 2005. The underwriters may, from time to time, engage in transactions with and perform services for us in the ordinary course of business.

VALIDITY OF THE COMMON UNITS

The validity of the common units will be passed upon for us by Vinson & Elkins L.L.P., Houston, Texas, and for the underwriters by Baker Botts L.L.P., Houston, Texas.

EXPERTS

The financial statements of Hiland Partners, LP as of December 31, 2003 and 2004, and for each of the three years in the period ended December 31, 2004; the financial statements of the net assets and operations acquired from Hiland Partners, LLC as of December 31, 2003 and 2004 and for each of the three years in the period ended December 31, 2004; the balance sheet of Hiland Partners, LP as of December 31, 2004; and the consolidated balance sheet of Hiland Partners GP, LLC and subsidiaries as of December 31, 2004; appearing in this prospectus and registration statement have been audited by Grant Thornton LLP, an independent registered public accounting firm, as indicated in their reports with respect thereto appearing elsewhere herein, and are included in reliance upon the authority of said firm as experts in giving such reports.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the Securities and Exchange Commission, or the SEC, a registration statement on Form S-l regarding the common units. This prospectus does not contain all of the information found in the registration statement. For further information regarding us and the common units offered by this prospectus, you may desire to review the full registration statement, including its exhibits and schedules, filed under the Securities Act. The registration statement of which this prospectus forms a part, including its exhibits and schedules, may be inspected and copied at the public reference room maintained by the SEC at Room 1024, 450 Fifth Street, N.W., Washington, D.C. 20549. Copies of the materials may also be obtained from the SEC at prescribed rates by writing to the public reference room maintained by the SEC at Room 1024, Judiciary Plaza, 450 Fifth Street, N.W., Washington, D.C. 20549. You may obtain information on the operation of the public reference room by calling the SEC at l-800-SEC-0330. The SEC maintains a web site on the Internet at http://www.sec.gov. Our registration statement, of which this prospectus constitutes a part, can be accessed from the SEC's web site.

We intend to furnish our unitholders annual reports containing our audited financial statements and furnish or make available quarterly reports containing our unaudited interim financial information for the first three fiscal quarters of each of our fiscal years.

FORWARD LOOKING STATEMENTS

This prospectus includes certain "forward-looking statements." These statements include statements regarding our plans, goals, beliefs or current expectations. Statements using words such as "anticipate," "believe," "intend," "project," "plan," "continue," "estimate," "forecast," "may," "will," or similar expressions help identify forward-looking statements. Although we believe such forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, no assurance can be given that every objective will be reached.

Actual results may differ materially from any results projected, forecasted, estimated or expressed in forward-looking statements since many of the factors that determine these results are subject to uncertainties and risks, difficult to predict, and beyond management's control. Such factors include:

- the general economic conditions in the United States of America as well as the general economic conditions and currencies in foreign countries;
- the continued ability to find and contract for new sources of natural gas supply;

the amount of natural gas transported on our gathering systems;

the level of throughput in our natural gas processing and treating facilities;

the fees we charge and the margins realized for our services;

the prices and market demand for, and the relationship between, natural gas and NGLs;

energy prices generally;

the level of domestic oil and natural gas production;

the availability of imported oil and natural gas;

actions taken by foreign oil and gas producing nations;

the political and economic stability of petroleum producing nations;

the weather in our operating areas;

the extent of governmental regulation and taxation;

hazards or operating risks incidental to the transporting, treating and processing of natural gas and NGLs that may not be fully covered by insurance;

competition from other midstream companies;

loss of key personnel;

the availability and cost of capital and our ability to access certain capital sources;

changes in laws and regulations to which we are subject, including tax, environmental, transportation and employment regulations;

the costs and effects of legal and administrative proceedings;

the ability to successfully identify and consummate strategic acquisitions at purchase prices that are accretive to our financial results; and

risks associated with the construction of new pipelines and treating and processing facilities or additions to our existing pipelines and facilities.

These factors are not necessarily all of the important factors that could cause actual results to differ materially from those expressed in any of our forward-looking statements. Our future results will depend upon various other risks and uncertainties, including, but not limited to those described elsewhere in "Risk Factors." Other unknown or unpredictable factors also could have material adverse effects on our future results. You should not put undue reliance on any forward-looking statements.

All forward-looking statements attributable to us are qualified in their entirety by this cautionary statement. We undertake no duty to update our forward-looking statements.

INDEX TO FINANCIAL STATEMENTS

HILAND PARTNERS, LP

UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS

Introduction

The following are our unaudited pro forma consolidated balance sheet as of September 30, 2005 and our unaudited pro forma consolidated statements of operations for the nine month period ended September 30, 2005 and for the year ended December 31, 2004. Our unaudited pro forma consolidated financial statements and accompanying notes should be read together with the financial statements and related notes included elsewhere in the prospectus.

The unaudited pro forma consolidated balance sheet gives pro forma effect to this offering of 1.6 million common units at an offering price of $41.77 per common unit and our general partner's proportionate capital contribution, resulting in aggregate net proceeds to us of $64.2 million, as if they had occurred on September 30, 2005.

The unaudited pro forma consolidated statements of operations give pro forma effect to the following transactions as if they had occurred on January 1, 2004:

- the Bakken acquisition;
- borrowings under our amended credit facility to fund the Bakken acquisition;
- this offering of 1.6 million common units at an offering price of $41.77 per common unit and our general partner's proportionate capital contribution, resulting in aggregate net proceeds to us of $64.2 million; and
- our initial public offering of 2.3 million common units at an offering price of $22.50 per common unit and the formation transactions related to our partnership including the contribution by Hiland Partners, LLC to us of all of its assets and liabilities other than the Bakken gathering system and a portion of its working capital assets and liabilities.

The unaudited pro forma consolidated balance sheet was derived by adjusting our historical unaudited consolidated balance sheet for the above transactions. The pro forma unaudited consolidated statements of operations were derived by adjusting our historical statements of operations and the historical statements of operations of our predecessor Continental Gas, Inc. The adjustments are based on currently available information and, therefore, the actual adjustments may differ from the pro forma adjustments. However, our management believes that the assumptions provide a reasonable basis for presenting the significant effects of the transactions described above and that the pro forma adjustments give appropriate effect to the assumptions made and are properly applied in the pro forma financial statements. The fair values of assets acquired or contributed are based on our management's estimate of fair values and, although they are believed to be reasonable, purchase price allocations are subject to change as we gather additional information to finalize the fair values of assets acquired. The unaudited pro forma financial statements do not purport to present our financial position or results of operations had the transactions described above actually been completed as of the dates indicated. Moreover, the statements do not project our financial position or results of operations for any future date or period.

HILAND PARTNERS, LP
UNAUDITED PRO FORMA CONSOLIDATED BALANCE SHEET
SEPTEMBER 30, 2005

	Historical	Adjustments	Pro Forma
	Hiland Partners, LP	Offering	Hiland Partners, LP
		(in thousands)	
ASSETS			
Current assets:			
Cash and cash equivalents	$ 6,816	$ 66,832 (a) (4,016)(b) 1,364 (c) (64,180)(d)	$ 6,816
Accounts receivable:			
Trade	18,601		18,601
Affiliates	1,107		1,107
	19,708		19,708
Inventories	153		153
Other current assets	347		347
Total current assets	27,024		27,024
Property and equipment, net	116,239		116,239
Intangibles, net	42,281		42,281
Other assets, net	1,007		1,007
Total assets	$ 186,551	$	$ 186,551
TOTAL LIABILITIES AND PARTNERS' CAPITAL			
Current liabilities:			
Accounts payable	$ 11,719	$	$ 11,719
Accounts payable-affiliates	7,660		7,660
Accrued liabilities	943		943
Total current liabilities	20,322		20,322
Commitments and contingencies			
Long-term debt, net of current maturities	93,700	(64,180)(d)	29,520
Asset retirement obligation	1,042		1,042
Partners' capital:			
Common unitholders	45,585	66,832 (a) (4,016)(b)	108,401
Subordinated unitholders	25,186		25,186
General partner interest	1,040	1,364 (c)	2,404
Unearned compensation	(324)		(324)
Total partners' capital	71,487	64,180	135,667
Total liabilities and partners' capital	$ 186,551	$	$ 186,551

See accompanying notes to unaudited pro forma financial statements.

HILAND PARTNERS, LP
UNAUDITED PRO FORMA CONSOLIDATED STATEMENT OF OPERATIONS
NINE MONTHS ENDED SEPTEMBER 30, 2005

	Historical	Historical	Adjustments			Pro Forma
	Hiland Partners, LP	Net Assets Acquired From Hiland Partners, LLC	IPO Formation Transactions and the Bakken Acquisition	As Adjusted for IPO Formation Transactions and the Bakken Acquisition	Adjustments Offering	Hiland Partners, LP
	(in thousands, except per unit amounts)					
Revenues:						
Midstream operations						
Third parties	$ 91,780	$ 18,313	$	$ 110,093	$	$ 110,093
Affiliates	3,514			3,514		3,514
Compression services, affiliate	3,012	336		3,348		3,348
Total revenues	98,306	18,649		116,955		116,955
Operating costs and expenses:						
Midstream purchases third parties (exclusive of items shown separately below)	50,750	10,140		60,890		60,890
Midstream purchases affiliates (exclusive of items shown separately below)	26,798	2,885		29,683		29,683
Operations and maintenance	5,083	1,679		6,762		6,762
Depreciation, amortization and accretion	6,924	1,843	348(e) 1,787(f)	10,902		10,902
General and administrative	1,539	254		1,793		1,793
Total operating costs and expenses	91,094	16,801	2,135	110,030		110,030
Operating income	7,212	1,848	(2,135)	6,925		6,925
Other income (expense):						
Interest and other income	112	3		115		115
Amortization of deferred loan costs	(360)	(127)	(162)(g)	(649)		(649)
Interest expense	(766)	(1,255)	(2,348)(h)	(4,369)	2,760(i)	(1,609)
Total other income (expense)	(1,014)	(1,379)	(2,510)	(4,903)	2,760	(2,143)

		Historical	Adjustments			
Net income	6,198	$ 469	$ (4,645)	2,022	$ 2,760	4,782
Less income attributable to predecessor	493					
Less general partner share of net income	128			48		108
Limited partner share of net income	$ 5,577			$ 1,974		$ 4,674
Net income per limited partners' unit:						
Basic	$ 0.82			$ 0.29		$ 0.56
Diluted	$ 0.82			$ 0.29		$ 0.55
Weighted-average limited partners' units outstanding:						
Basic	6,800			6,800		8,400
Diluted	6,830			6,830		8,430

See accompanying notes to unaudited pro forma financial statements.

HILAND PARTNERS, LP
UNAUDITED PRO FORMA CONSOLIDATED STATEMENT OF OPERATIONS
YEAR ENDED DECEMBER 31, 2004

	Historical	Historical	Adjustments			Pro Forma
	Hiland Partners, LP	Net Assets Acquired From Hiland Partners, LLC	IPO Formation Transactions and the Bakken Acquisition	As Adjusted for IPO Formation Transactions and the Bakken Acquisition	Adjustments Offering	Hiland Partners, LP
	(in thousands, except per unit amounts)					
Revenues:						
Midstream operations						
Third parties	$ 95,019	$ 9,379	$	$ 104,398	$	$ 104,398
Affiliates	3,277	1,102		4,379		4,379
Compression services, affiliate		3,854		3,854		3,854
Total revenues	98,296	14,335		112,631		112,631
Operating costs and expenses:						
Midstream purchases third parties (exclusive of items shown separately below)	54,962	2,795		57,757		57,757
Midstream purchases affiliates (exclusive of items shown separately below)	27,570	1,805		29,375		29,375
Operations and maintenance	4,933	2,080		7,013		7,013
Depreciation, amortization and accretion	4,127	2,311	2,894(e) 534(f)	9,866		9,866
Gain on sale of assets	(19)			(19)		(19)
General and administrative	1,082	97		1,179		1,179
Total operating costs and expenses	92,655	9,088	3,428	105,171		105,171
Operating income	5,641	5,247	(3,428)	7,460		7,460
Other income (expense):						
Interest and other income	40	1		41		41
Amortization of deferred loan costs	(102)	(106)	(178)(j) (432)(g)	(818)		(818)
Interest expense	(702)	(661)	1,223(k) (4,077)(h)	(4,217)	2,888(i)	(1,329)
Total other income (expense)	(764)	(766)	(3,464)	(4,994)	2,888	(2,106)
Net income	$ 4,877	$ 4,481	$ (6,892)	$ 2,466	$ 2,888	5,354

	Historical	Adjustments		
Less general partner share of net income				107
Limited partner share of net income			$	5,247
Net income per limited partners' unit:				
Basic			$	0.62
Diluted			$	0.62
Weighted-average limited partners' units outstanding:				
Basic				8,400
Diluted				8,400

See accompanying notes to unaudited pro forma financial statements.

HILAND PARTNERS, LP

NOTES TO UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Basis of Presentation, the Initial Public Offering and Other Transactions

The unaudited pro forma consolidated balance sheet gives pro forma effect to this offering of 1.6 million common units at an offering price of $41.77 per common unit and our general partner's proportionate capital contribution, resulting in aggregate net proceeds to us of $64.2 million, as if they had occurred on September 30, 2005.

The unaudited pro forma consolidated statements of operations give pro forma effect to the following transactions as if they had occurred on January 1, 2004:

- the Bakken acquisition;
- borrowings under our amended credit facility to fund the Bakken acquisition;
- this offering of 1.6 million common units at an offering price of $41.77 per common unit and our general partner's proportionate capital contribution, resulting in aggregate net proceeds to us of $64.2 million; and
- our initial public offering of 2.3 million common units at an offering price of $22.50 per common unit and the formation transactions related to our partnership including the contribution by Hiland Partners, LLC to us of all of its assets and liabilities other than the Bakken gathering system and a portion of its working capital assets and liabilities.

Note 2. Pro Forma Adjustments and Assumptions

(a) Reflects the proceeds to us of $66.8 million from the issuance and sale of 1,600,000 common units at an offering price of $41.77 per common unit.

(b) Reflects the payment of underwriters' discounts and commissions and other estimated offering expenses of $4.0 million. The underwriters' discounts and commissions and offering expenses will be allocated to the common units issued.

(c) Reflects the contribution of $1.4 million from our general partner in order to maintain its 2% interest in Hiland Partners, LP.

(d) Represents the repayment of $64.2 million borrowed under our credit facility from the aggregate net proceeds of $64.2 million from this offering and our general partner's capital contribution which will reduce our outstanding indebtedness to $29.5 million under our bank credit facility.

(e) Represents the increase in depreciation, amortization and accretion expense related to the increase in carrying value of tangible and intangible assets of Hiland Partners, LLC that were contributed to us in connection with our formation. These assets do not include the Bakken gathering system. A determination was made by management of the fair value of these assets and liabilities primarily using current replacement cost for gas plant property, equipment and pipelines less estimated accumulated depreciation on such replacement costs; estimated discounted cash flows for systems contracts and customer relationships; and liabilities at the present value of estimated amounts to be paid based on Hiland Partners, LLC's then current interest rates. Systems contracts and customer relationships are amortized over estimated lives of 10 years.

(f) Reflects the additional depreciation, amortization and accretion expense from the acquisition of the Bakken gathering system which commenced operations in November 2004. Pro forma depreciation and amortization expense was based on estimated useful lives of 15 years for the

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plant and gathering system assets and ten years for the intangible assets. Due to our new carrying value of these assets, historical depreciation expense and impairment expense on the assets have been increased in these pro forma statements.

(g) Reflects the amortization of deferred loan costs had the Bakken acquisition taken place on January 1, 2004 and the write off of unamortized deferred loan costs of Hiland Partners, LLC at September 30, 2005.

(h) Reflects the increase of interest expense resulting from the borrowings under our revolving credit facility of $93.7 million in connection with the Bakken acquisition. The interest rates used to determine the pro forma adjustment for the borrowings under the revolving credit facility were based on our weighted-average borrowing rates of 5.7% and 4.5% for the nine months ended September 30, 2005 and the year ended December 31, 2004, respectively.

(i) Reflects the reduction of interest expense resulting from repayment of the $64.2 million of borrowings under our bank credit facility with the aggregate net proceeds of $64.2 million from this offering and our general partner's capital contribution. The interest rates used to determine the pro forma adjustment for the borrowings under the revolving credit facility were based on our weighted-average borrowing rates of 5.7% and 4.5% for the nine months ended September 30, 2005 and the year ended December 31, 2004, respectively.

(j) Reflects the write off of unamortized deferred loan cost of Continental Gas, Inc. due to debt repayment in connection with our formation and initial public offering.

(k) Reflects the elimination of interest expense due to the repayment of outstanding indebtedness of Continental Gas, Inc. and the repayment of outstanding indebtedness on the assets contributed by Hiland Partners, LLC from the proceeds of our initial public offering.

Note 3. Pro Forma Net Income Per Unit

Pro forma net income per unit is determined by dividing the pro forma net income per unit that would have been allocated to the common and subordinated unitholders, which is 98% of pro forma net income, by the number of common and subordinated units expected to be outstanding at the closing of this offering. For purposes of this calculation, the number of common and subordinated units assumed to be outstanding was 8,400,000. All units were assumed to have been outstanding since January 1, 2004. Pursuant to our partnership agreement, to the extent that the quarterly distributions exceed certain targeted levels, the general partner is entitled to receive certain incentive distributions that will result in less net income proportionately being allocated to the holders of common and subordinated units. The pro forma net income per unit calculations reflect incentive distributions made to our general partner based upon the pro forma available cash from operating surplus for the period.

Note 4. Description of Equity Interest in the Partnership

The common units and subordinated units represent limited partner interests in the Partnership. The holders of units are entitled to participate in partnership distributions and exercise the rights and privileges available to limited partners under the partnership agreement of the Partnership.

The common units have the right to receive a minimum quarterly distribution of $0.45 per unit, or $1.80 on an annualized basis, plus any arrearages on the common units, before any distribution is made to the holders of subordinated units. In addition, if the aggregate ownership of common and subordinated units owned by persons other than the general partner and its affiliates is less than 20%, the general partner will have a right to call the common units at a price not less than the then-current market price of the common units.

The subordinated units generally receive quarterly cash distributions only when common units have received a minimum quarterly distribution of $0.45 per unit for each quarter since the commencement of operations. Subordinated units will convert into common units on a one-for-one basis when the subordination period ends. The subordination period will end when the Partnership meets financial tests specified in the partnership agreement but generally cannot end before March 31, 2010. The subordinated units have an early conversion-to-common-units potential of 25% after March 31, 2008 and 25% after March 31, 2009, if certain distribution targets are achieved.

The general partner interest is entitled to at least 2% of all distributions made by the Partnership. In addition, the general partner holds incentive distribution rights, which allow the general partner to receive a higher percentage of quarterly distributions of available cash from operating surplus after the minimum quarterly distributions have been achieved, and as additional target levels are met. The higher percentages range from 15% up to 50%. The pro forma financial statements reflect incentive distributions made to our general partner.

Report of Independent Registered Public Accounting Firm

Board of Directors
Hiland Partners GP, LLC

We have audited the accompanying balance sheets of Hiland Partners, LP, (the Partnership) (Note 1) as of December 31, 2003 and 2004, and the related statements of operations, cash flows, and changes in owners' equity for each of the three years in the period ended December 31, 2004. 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 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 financial statements referred to above present fairly, in all material respects, the financial position of Hiland Partners, LP as of December 31, 2003 and 2004, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the financial statements, effective January 1, 2003, the Partnership adopted Statement of Financial Accounting Standards No. 143 and changed its method of accounting for asset retirement obligations.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 15, 2005

HILAND PARTNERS, LP
BALANCE SHEETS

	Predecessor December 31, 2003	Predecessor December 31, 2004	September 30, 2005 (unaudited)
	(in thousands)		
ASSETS			
Current assets:			
Cash and cash equivalents	$ 496	$ 217	$ 6,816
Accounts receivable:			
Trade	7,832	9,663	18,601
Affiliates	532	758	1,107
	8,364	10,421	19,708
Inventories	275	153	153
Other current assets	5	118	347
Total current assets	9,140	10,909	27,024
Property and equipment, at cost, net	38,425	37,075	116,239
Intangibles, net			42,281
Other assets, net	275	1,191	1,007
Total assets	$ 47,840	$ 49,175	$ 186,551
LIABILITIES AND OWNERS' EQUITY			
Current liabilities:			
Accounts payable	$ 5,330	$ 5,649	$ 11,719
Accounts payable affiliates	2,814	2,998	7,660
Accrued liabilities	311	327	943
Current maturities of long-term debt	2,429	2,429	
Total current liabilities	10,884	11,403	20,322
Commitments and contingencies			
Long-term debt, net of current maturities	14,571	12,643	93,700
Asset retirement obligation	646	619	1,042
Owners' equity:			
Predecessor stockholders' equity	21,739	24,510	
Common unitholders (2,728,000 units issued and outstanding at September 30, 2005)			45,585
Subordinated unitholders (4,080,000 units issued and outstanding at September 30, 2005)			25,186
General partner interest			1,040
Unearned compensation			(324)
Total owners' equity	21,739	24,510	71,487

	Predecessor		
Total liabilities and owners' equity	$ 47,840	$ 49,175	$ 186,551

The accompanying notes are an integral part of these financial statements.

HILAND PARTNERS, LP
STATEMENTS OF OPERATIONS

	Predecessor				
	Year Ended December 31,				
	2002	2003	2004	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2005
				(unaudited)	
	(in thousands, except per unit amounts)				
Revenues:					
Midstream operations					
Third parties	$ 33,789	$ 73,666	$ 95,019	$ 67,952	$ 91,780
Affiliates	1,439	2,352	3,277	2,334	3,514
Compression services, affiliate					3,012
Total revenues	35,228	76,018	98,296	70,286	98,306
Operating costs and expenses:					
Midstream purchases (exclusive of items shown separately below)	14,654	40,760	54,962	39,525	50,750
Midstream purchases affiliate (exclusive of items shown separately below)	13,281	26,242	27,570	20,321	26,798
Operations and maintenance	3,509	3,714	4,933	3,624	5,083
Property impairment		1,535			
Depreciation, amortization and accretion	2,370	3,304	4,127	3,003	6,924
(Gain) loss on asset sales	(12)	34	(19)	(15)	
General and administrative	730	770	1,082	680	1,539
Bad debt	295				
Total operating costs and expenses	34,827	76,359	92,655	67,138	91,094
Operating income (loss)	401	(341)	5,641	3,148	7,212
Other income (expense):					
Interest and other income	72	10	40	23	112
Amortization of deferred loan costs		(24)	(102)	(76)	(360)
Interest expense		(130)	(702)	(508)	(766)
Interest expense affiliate	(185)	(343)			
Total other income (expense)	(113)	(487)	(764)	(561)	(1,014)
Income (loss) from continuing operations	288	(828)	4,877	2,587	6,198
Discontinued operations, net	199	246	35	34	

	Predecessor				
Income (loss) before cumulative effect of change in accounting principle	487	(582)	4,912	2,621	6,198
Cumulative effect of change in accounting principle		1,554			
Net income	$ 487	$ 972	$ 4,912	$ 2,621	6,198
Less income attributable to predecessor					493
Less general partner interest in net income					128
Limited partners' interest in net income					$ 5,577
Net income per limited partners' unit basic					$ 0.82
Net income per limited partners' unit diluted					$ 0.82
Weighted average limited partners' units outstanding basic					6,800
Weighted average limited partners' units outstanding diluted					6,830

The accompanying notes are an integral part of these financial statements.

HILAND PARTNERS, LP
STATEMENTS OF CASH FLOWS

	Predecessor				
	Year Ended December 31,			Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2005
	2002	2003	2004		
				(unaudited)	
				(in thousands)	
Cash flows from operating activities:					
Net income	$ 487	$ 972	$ 4,912	$ 2,621	$ 6,198
Adjustments to reconcile net income to net cash provided by operating activities:					
Cumulative effect of change in accounting principle		(1,724)			
Depreciation and amortization	2,510	3,448	4,170	3,052	6,898
Change in asset retirement obligation		25	23	18	26
Amortization of deferred loan cost		24	102	76	360
Bad debt expense	(295)				
Property impairments		1,535			
Loss (gain) on sale of assets	51	41	(19)	(15)	
(Increase) decrease in current assets:					
Accounts receivable	561	(4,349)	(1,831)	218	(14,413)
Accounts receivable affiliates	(118)	(168)	(226)	223	(153)
Inventories	(8)		122	122	
Other current assets	3	5	(113)	(9)	(163)
Increase (decrease) in current liabilities:					
Accounts payable	323	3,704	319	642	(938)
Accounts payable affiliates	1,273	664	482	(85)	2,658
Accrued liabilities	22	287	16	48	427
Net cash provided by operating activities	4,809	4,464	7,957	6,911	900
Cash flows from investing activities:					
Additions to property and equipment	(5,760)	(5,389)	(5,326)	(4,876)	(2,770)
Assets of business acquired		(12,025)			
Acquisition of net assets of Hiland Partners, LLC, less cash received					(62,440)
Proceeds from disposals of property and equipment	115	128	36	9	
Net cash used in investing activities	(5,645)	(17,286)	(5,290)	(4,867)	(65,210)
Cash flows from financing activities:					
Proceeds from public offering, net					48,128
Redemption of common units					(6,278)
Distributions to organizers					(3,851)
Cash not contributed by organizers					(869)
Borrowings from affiliate	1,491	13,598			
Repayments to affiliates	(975)	(17,089)			
Long-term borrowings from third parties		17,000	500		93,700
Repayments of long-term borrowings from third parties			(2,428)		
Payments on long-term borrowings				(1,821)	(23,951)
Debt issuance cost				(5)	(1,189)

	Predecessor				
Payment of offering cost					(2,249)
Cash distribution to unitholders					(4,770)
Contribution by general partner					6
Cash distribution to controlling member for net assets of Hiland Partners, LLC					(27,768)
Increase in deferred loan costs		(297)	(6)		
Increase in deferred offering costs			(1,012)	(431)	
Net cash provided by (used in) financing activities	516	13,212	(2,946)	(2,257)	70,909
Increase (decrease) for the period	(320)	390	(279)	(213)	6,599
Beginning of period	426	106	496	496	217
End of period	$ 106	$ 496	$ 217	$ 283	$ 6,816
Supplementary information					
Cash paid for interest	$ 61	$ 239	$ 787	$ 602	$ 367
Non cash investing and financing activities:					
Effective January 1, 2003 the company recorded the cumulative effect of SFAS No 143 for asset retirement obligation as follows:					
Increase in property and equipment		$ 2,250			
Increase in asset retirement obligation		(526)			
Cumulative effect of accounting change		$ 1,724			
Transfer to shareholder on May 31, 2004 of oil and gas properties with a net book value of $2,489, accounts payable of $298 and asset retirement obligations of $50.					
Transfer from property and equipment to inventory		$ 122			
Transfer from inventory to property and equipment		(218)			
Change in inventory, 2003		$ (96)			

The accompanying notes are an integral part of these financial statements.

HILAND PARTNERS, LP
STATEMENT OF CHANGES IN OWNERS' EQUITY

		Hiland Partners, LP				
	Predecessor	Common Units	Subordinated Units	General Partner Interest	Unearned Compensation	Total
			(in thousands)			
Balance January 1, 2002	$ 20,280	$	$	$	$	$ 20,280
Net income	487					487
Balance December 31, 2002	20,767					20,767
Net income	972					972
Balance December 31, 2003	21,739					21,739
Net income	4,912					4,912
Transfer of discontinued operations to parent company	(2,141)					(2,141)
Balance December 31, 2004	24,510					24,510
Unaudited nine months ended September 30, 2005:						
Assets not contributed to Hiland Partners, LP	(9,972)					(9,972)
Net income from January 1, 2005 through February 14, 2005	493					493
Allocation of net parent investment to unitholders	(15,031)	2,191	12,418	422		
Contribution of Hiland Partners, LLC by owners		7,092	40,190	1,367		48,649
Proceeds from initial public offering, net of underwriter discount		48,128				48,128
Offering costs		(3,365)				(3,365)
Redemption of Common Units from Organizers		(6,278)				(6,278)
Distributions at organization		(362)	(3,489)			(3,851)
Cash distribution to controlling member for net assets of Hiland Partners, LLC		(2,507)	(24,473)	(788)		(27,768)
Contribution by general partner				6		6
Periodic cash distributions		(1,870)	(2,805)	(95)		(4,770)
Issuance of restricted units		324			(324)	
Net income from February 15, 2005		2,232	3,345	128		5,705

		Hiland Partners, LP				
through September 30, 2005						
Balance September 30, 2005 (unaudited)	$	$ 45,585	$ 25,186	$ 1,040	$ (324)	$ 71,487

The accompanying notes are an integral part of this financial statement.

HILAND PARTNERS, LP
NOTES TO FINANCIAL STATEMENTS

(Information as of September 30, 2005 and for the Nine Months Ended September 30, 2004 and 2005 is Unaudited)
(in thousands, except unit and per unit information or unless otherwise noted)

Note 1: Description of Business and Summary of Significant Accounting Policies

Description of Business

Hiland Partners, LP, a Delaware limited partnership ("we," "us," "our," "HPLP" or "the Partnership"), was formed in October 2004 to acquire and operate certain of the midstream natural gas plants, gathering systems and compression and water injection assets previously owned by Continental Gas, Inc. and Hiland Partners, LLC. HPLP commenced operations on February 15, 2005, and concurrently with the completion of its initial public offering, Continental Gas, Inc. ("Predecessor" or "CGI") contributed a substantial portion of its net assets to HPLP.

CGI constitutes HPLP's predecessor. The transfer of ownership of net assets from CGI to HPLP represented a reorganization of entities under common control and was recorded at historical cost. Accordingly, the financial statements include the historical operations of CGI prior to the transfer to HPLP. CGI was formed in 1990 as a wholly owned subsidiary of Continental Resources, Inc. ("CRI").

CGI operated in one segment, midstream, which involved the gathering, compressing, dehydrating, treating, and processing of natural gas and fractionating natural gas liquids, or NGLs. CGI historically has owned all of our natural gas gathering, processing, treating and fractionation assets other than our Worland gathering system and our Bakken gathering system. Hiland Partners, LLC historically owned our Worland gathering system and our compression services assets, which we acquired on February 15, 2005, and our Bakken gathering system. Since the initial public offering, the Partnership has operated in midstream and compression services segments. On September 26, 2005, the Partnership acquired Hiland Partners, LLC, which at such time owned the Bakken gathering system, for $92.7 million, $35.0 million of which was used to retire outstanding Hiland Partners, LLC indebtedness.

CGI had minor interests in producing oil and gas properties located primarily in North Dakota. The properties were acquired over several years while CGI was a subsidiary of CRI. CGI did not intend to pursue the exploration for and development of oil and natural gas and, accordingly, conveyed its interest in these properties effective May 31, 2004 to CRI. Therefore, this activity is presented as discontinued operations.

In July 2004, CRI sold all of the issued and outstanding capital stock of CGI to the shareholders of CRI at fair value. The stock sale transaction was approved by all of the independent members of the Board of Directors of CRI, and the independent members of the Board of Directors were provided with an opinion as to the fairness of the stock sale transaction, from a financial point of view. CGI and CRI were previously consolidated and subsequently were affiliated corporations because of common ownership.

The financial statements for the nine months ended September 30, 2004 and 2005 included herein have been prepared without audit, pursuant to the rules and regulations of the United States Securities and Exchange Commission (the "SEC"). The interim financial statements reflect all adjustments, which are in the opinion of our management, necessary for a fair presentation of our results for the interim periods. Such adjustments are considered to be of a normal recurring nature. Results of operations for the nine months ended September 30, 2005 are not necessarily indicative of the results of operations that will be realized for the year ending December 31, 2005.

The consolidated financial statements include our accounts and those of our subsidiaries. All significant intercompany transactions and balances have been eliminated. The consolidated financial statements include the net assets and operations of assets owned by CGI and Hiland Partners, LLC that were contributed to us concurrently with the completion of our initial public offering and also include the net assets and operations of Hiland Partners, LLC acquired effective September 1, 2005.

Use of Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates.

Cash and Cash Equivalents

We consider all highly liquid investments with maturity of three months or less at the time of purchase to be cash equivalents.

Accounts Receivable

The majority of our accounts receivable are due from companies in the oil and gas industry as well as the utility industry. Credit is extended based on evaluation of the customer's financial condition. In certain circumstances, collateral, such as letters of credit or guarantees, is required. Accounts receivable are due within 30 days and are stated at amounts due from customers. We have established various procedures to manage its credit exposure, including initial credit approvals, credit limits and rights of offset. Credit losses are charged to income when accounts are deemed uncollectible, determined on a case-by-case basis when we believe the required payment of specific amounts owed is unlikely to occur. These losses historically have been minimal, therefore, an allowance for uncollectible accounts is not required.

In December 2001, Enron Corporation and its subsidiaries ("Enron") filed for bankruptcy protection. As a result of our review of subsequent financial information on Enron, we wrote off $295 in accounts receivable from Enron in the first quarter of 2002.

Inventories

Inventories consist primarily of compressors and associated equipment. Inventories are stated at the lower of cost or estimated net realizable value.

Concentration and Credit Risk

Financial instruments that potentially subject us to concentrations of credit risk consist principally of cash and cash equivalents and receivables.

We place our cash and cash equivalents with high-quality institutions and in money market funds. We derive our revenue from customers primarily in the natural gas and utility industries. These industry concentrations have the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers could be affected by similar changes in economic, industry or other conditions. However, we believe that the credit risk posed by this industry concentration is offset by the creditworthiness of our customer base. Our portfolio of accounts receivable is comprised primarily of mid-size to large domestic corporate entities.

Fair Value of Financial Instruments

Our financial instruments, which require fair value disclosure, consist primarily of cash and cash equivalents, accounts receivable, accounts payable and bank debt. The carrying value of cash and cash equivalents, accounts receivable and accounts payable are considered to be representative of their respective fair values, due to the short maturity of these instruments. The fair value of long-term debt approximates its carrying value due to the variable interest rate feature of such debt.

Long-Lived Assets

In accordance with Statement of Financial Accounting Standards (SFAS) No. 144, "*Accounting for the Impairment or Disposal of Long-Lived Assets*," we evaluate our long-lived assets of identifiable business activities for impairment when events or changes in circumstances indicate, in our management's judgment, that the carrying value of such assets may not be recoverable. The determination of whether impairment has occurred is based on our management's estimate of undiscounted future cash flows attributable to the assets as compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value for the assets and recording a provision for loss if the carrying value is greater than fair value. For assets identified to be disposed of in the future, the carrying value of these assets is compared to the estimated fair value less the cost to sell to determine if impairment is required. Until the assets are disposed of, an estimate of the fair value is re-determined when related events or circumstances change.

When determining whether impairment of one of our long-lived assets has occurred, we must estimate the undiscounted cash flows attributable to the asset or asset group. Our estimate of cash flows is based on assumptions regarding the volume of reserves providing asset cash flow and future NGL product and natural gas prices. The amount of reserves and drilling activity are dependent in part on natural gas prices. Projections of reserves and future commodity prices are inherently subjective and contingent upon a number of variable factors, including, but not limited to:

- changes in general economic conditions in regions in which the Partnership's products are located;
- the availability and prices of NGL products and competing commodities;
- the availability and prices of raw natural gas supply;
- our ability to negotiate favorable marketing agreements;
- the risks that third party oil and gas exploration and production activities will not occur or be successful;
- our dependence on certain significant customers and producers of natural gas; and
- competition from other midstream service providers and processors, including major energy companies.

Any significant variance in any of the above assumptions or factors could materially affect our cash flows, which could require us to record an impairment of an asset.

In December 2003, as a result of volume declines at gathering facilities located in Texas, Mississippi and Wyoming, CGI recognized an impairment charge of $1.5 million. No impairment charges were recognized during each of the years ended December 31, 2002 and 2004.

Revenue Recognition

Revenues for sales of natural gas and NGLs are recognized at the time all gathering and processing activities are completed, the product is delivered and title is transferred. Revenues from oil and gas production (discontinued operations) are recorded in the month produced and title is transferred to the purchaser.

Derivatives

Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. SFAS No. 133 requires that an entity recognize all derivatives as either assets or liabilities in the statement of financial position and measure those instruments at fair value. SFAS No. 133 provides that normal purchases and normal sales contracts are not subject to the statement. Normal purchases and normal sales are contracts that provide for the purchase or sale of something other than a financial instrument or derivative instrument that will be delivered in quantities expected to be used or sold by the reporting entity over a reasonable period in the normal course of business. Our forward natural gas purchase and sales contracts are designated as normal purchases and sales. Substantially all forward contracts fall within a one-month to five-year term.

Property and Equipment

Our property and equipment are carried at cost. Depreciation and amortization of all equipment is determined under the straight-line method using various rates based on useful lives, 10 to 23 years for pipeline and processing plants, and 3 to 10 years for corporate and other assets. The cost of assets and related accumulated depreciation is removed from the accounts when such assets are disposed of, and any related gains or losses are reflected in current earnings. Maintenance, repairs and minor replacements are expensed as incurred. Costs of replacements constituting improvement are capitalized.

Intangible Assets

Intangible assets consist of the acquired value of existing contracts to sell natural gas and other NGLs and compression contracts, which do not have significant residual value. The contracts are being amortized over ten years. Net intangible assets of $42,281 as of September 30, 2005 consisted of $24,923 in gas sales contracts and $17,358 in compression contracts. The Partnership reviews intangible assets for impairment whenever events or circumstances indicate that the carrying amounts may not be recoverable. If such a review should indicate that the carrying amount of intangible assets is not recoverable, we reduce the carrying amount of such assets to fair value. No impairment of intangible assets has been recorded as of September 30, 2005.

Environmental Costs

Environmental costs are expensed if they relate to an existing condition caused by past operations and do not contribute to current or future revenue generation. Liabilities are recorded when site restoration and environmental remediation and cleanup obligations are either known or considered probable and can be reasonably estimated. Recoveries of environmental costs through insurance, indemnification arrangements or other sources are included in other assets to the extent such recoveries are considered probable.

Income Taxes

As a partnership we are not subject to income taxes. Accordingly, there is no provision for income taxes included in the consolidated financial statements. Taxable income, gain, loss and deductions are allocated to the owners who are responsible for payment of any taxes thereon.

Transportation and Exchange Imbalances

In the course of transporting natural gas and NGLs for others, we may receive for redelivery different quantities of natural gas or NGLs than the quantities actually redelivered. These transactions result in transportation and exchange imbalance receivables or payables that are recovered or repaid through the receipt or delivery of natural gas or NGLs in future periods, if not subject to cashout provisions. Imbalance receivables are included in accounts receivable and imbalance payables are included in accounts payable on the balance sheets and marked-to-market using current market prices in effect for the reporting period of the outstanding imbalances. Changes in market value and the settlement of any such imbalance at a price greater than or less than the recorded imbalance results in either an upward or downward adjustment, as appropriate, to the cost of natural gas sold. As of December 31, 2003 and 2004, we had no imbalance receivables or payables.

Share-Based Compensation

The Partnership applies Accounting Principles Board Opinion No. 25 and related interpretations in accounting for its share-based compensation awards. Accordingly, no compensation cost has been recognized for unit options granted in the accompanying consolidated financial statements. We had granted no unit options until adoption of our incentive unit option plan on February 15, 2005. The following pro forma data is calculated as if compensation cost for our share-based compensation awards was determined based upon the fair value at the grant date consistent with the methodology prescribed under SFAS No. 123.

	Nine Months Ended September 30, 2005	
Net income as reported	$	6,198
Share based compensation adjustment		(739)
Pro forma net income		5,459
Less: income attributable to predecessor		493
Less: general partner interest		111
Limited partner's interest in pro forma net income	$	4,855
Net income per limited partner unit as reported, basic	$	0.82
Net income per limited partner unit as reported, diluted	$	0.82
Adjustment, basic	$	(0.11)
Adjustment, diluted	$	(0.11)
Pro forma net income per limited partner unit, basic	$	(0.71)
Pro forma net income per limited partner unit, diluted	$	(0.71)
Weighted average limited partner units outstanding, basic		6,800,000
Weighted average limited partner units outstanding, diluted		6,830,000

As of September 30, 2005, there were 166,000 options outstanding with a weighted-average exercise price of $24.53 per unit and a weighted-average grant date fair value of $12.43 per unit. As of September 30, 2005, no options were exercisable. The fair value of each option granted was estimated on the date of grant using the American Binomial option pricing model with the following weighted average assumptions used for grants in 2005: risk-free interest rates of 4.5 percent; 5.2 percent dividend yield; no assumed forfeitures; expected lives of 6.0 years; and volatility of 29.7 percent. The pro forma amounts above are not likely to be representative of future years because there is no assurance that additional awards will be made each year.

Recent Accounting Pronouncements

SFAS No. 143, "Accounting for Asset Retirement Obligations"

In June 2001, FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations," that requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement cost is allocated to expense using a systematic and rational method and the liability is accreted to measure the change in liability due to the passage of time. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002, with early adoption permitted. We adopted the standard effective January 1, 2003. The primary impact of this standard relates to dismantling and site restoration of certain of our plants and pipelines; and abandonment and plugging of oil and gas wells in which we participate (herein referenced as discontinued operations). Prior to SFAS 143, we had not recorded an obligation for these costs due to its assumption that the salvage value of the equipment would substantially offset the cost of dismantling the facilities and carrying out the necessary clean up and reclamation activities. The adoption of SFAS 143 on January 1, 2003, resulted in a net increase to Property and Equipment and Asset Retirement Obligations of approximately $2.3 million and $0.6 million, respectively, as a result of us separately accounting for salvage values and recording the estimated fair value of its dismantling, reclamation and plugging obligations on the balance sheet. The impact of adopting SFAS 143 has been accounted for through a cumulative effect adjustment that amounted to $1.7 million increase to net income recorded on January 1, 2003. The increase in expense resulting from the accretion of the asset retirement obligation and the depreciation of the additional capitalized plant, pipeline, and well costs is expected to be substantially offset by the decrease in depreciation from our consideration of the estimated salvage values in the depreciation calculation.

The following table summarizes our activity related to asset retirement obligations:

		Amount
Asset Retirement Obligation, January 1, 2003		$ 526
Plus:	Accretion expense	25
	Additions for new assets	95
Asset Retirement Obligation, December 31, 2003		646
Plus:	Accretion expense	23
Less:	Transfer of discontinued operations	(50)
Asset Retirement Obligation, December 31, 2004		619
Plus:	Acquired from Hiland Partners, LLC on February 15, 2005	397
	Accretion expense	26
Asset Retirement Obligation, September 30, 2005		$ 1,042

Pro forma asset retirement obligation at January 1, 2002 was $502. The effect of the change in accounting principle for 2003 was an increase to net income of $1,699, including $25 accretion of the asset retirement obligation.

The following table presents the pro forma effect on net income for the years December 31, 2002 and 2003 as if SFAS 143 had been adopted prior to January 1, 2002.

	Year Ended December 31,	
	2002	2003
Net income, as reported	$ 487	$ 972
Discontinued operations, net	(199)	(246)
Cumulative effect of change in accounting principle		(1,554)
Asset retirement obligation accretion expense	(18)	
Asset retirement cost depreciation expense	(29)	
Reduction in depreciation expense on salvage value	60	
Income (loss) from continuing operations, pro forma	301	(828)
Discontinued operations, net	199	246
Cumulative effect of change in accounting principle, discontinued operations		(170)
Asset retirement obligation accretion expense	(2)	
Asset retirement cost depreciation expense	(1)	
Reduction in depreciation expense on salvage value	6	
Net income (loss), pro forma	$ 503	$ (752)

SFAS No. 123, "Share-Based Payment"

In October 1995, the FASB issued SFAS No. 123, "Share-Based Payments," which was revised in December 2004 (collectively, "SFAS 123R"). SFAS 123R requires that the compensation cost relating to share-based payment transactions be recognized in financial statements and that cost will be measured based on the fair value of the equity or liability instruments issued. The effect of the standard will be to require entities to measure the cost of employee services received in exchange for stock or unit options based on the grant-date fair value of the award, and to recognize the cost over the period the employee is required to provide services for the award.

We will be required to apply SFAS 123R as of the first interim period beginning on or after January 1, 2006. We expect to apply the statement using the permitted modified prospective method beginning January 1, 2006. We are still evaluating the impact of this statement on our financial statements.

Note 2: Property and Equipment

	As of December 31,		As of September 30,
	2003	2004	2005
Land	$ 120	$ 127	$ 225
Pipelines and plants	46,971	53,745	138,381
Other	1,837	2,209	3,346
Oil and gas properties (discontinued)	4,718		
	53,646	56,081	141,952
Less: accumulated depreciation and amortization	15,221	19,006	25,713
	$ 38,425	$ 37,075	$ 116,239

Depreciation and amortization charged to expense, including discontinued operations, totaled $2,510, $3,448, and $4,170 for the years ended December 31, 2002, 2003 and 2004, respectively.

Note 3: Long-Term Debt

	As of December 31, 2003(a)	As of December 31, 2004(a)	As of September 30, 2005(b)
Note payable bank	$ 17,000	$ 15,072	$ 93,700
Less: current portion	2,429	2,429	
Long-term portion	$ 14,571	$ 12,643	$ 93,700

(a) On October 22, 2003, we closed a new $35.0 million secured credit facility consisting of a senior secured term loan facility of up to $25.0 million, and a senior revolving credit facility of up to $10.0 million. The initial availability of funds under the credit facility was $22.0 million, $17.0 million of which was a term loan facility. Prior to closing this new facility, we had borrowed funds from CRI under its credit facility. The initial advance under the term loan facility was $17.0 million, the majority of which was paid to CRI to reduce the outstanding balance on its credit facility. No funds were initially advanced under the revolving loan facility. Advances under either facility can be made, at the borrower's election, as reference rate loans or LIBOR loans and, with respect to the LIBOR loans, for interest periods of one, two, three, or six months. Interest is payable on the reference rate loans monthly and on LIBOR loans at the end of the applicable interest period. The principal amount of the term loan facility is amortized on a quarterly basis through June 30, 2006, with the final payment due on September 30, 2006. The amount available under the revolving loan facility may be borrowed, repaid and reborrowed until maturity on September 30, 2006. Interest on reference rate loans is calculated with a reference to a rate equal to the higher of the reference rate of the bank or the federal funds rate plus 0.5%. Interest on LIBOR loans is calculated with reference to the London interbank offered interest rate. Interest accrues at the reference rate or the LIBOR rate, as applicable, plus the applicable margins. The margin is based on the then current senior debt to EBITDA ratio. The credit agreement requires quarterly mandatory prepayments on the term loan of $607 and 75% of excess cash flow. The credit facility is collateralized by a pledge of all of our assets. As of December 31, 2004, the effective interest rate under the facility was 4.9%. The credit agreement contains certain covenants. CGI must maintain a current ratio of not less than 1.0 to 1.0; interest charge coverage ratio of 3.0 to 1.0; fixed charge coverage ratio of 1.5 to 1.0; and a senior debt to EBITDA ratio of 3.25 to 1.0. As of December 31, 2004, CGI was in compliance with its financial covenants. The agreement limits CGI's ability to assume further indebtedness, assume contingent liabilities, sell assets, make investments, cancel insurance, amend, waive, or terminate material contracts, redeem senior subordinated notes, merge or consolidate, distribute cash to owners, change its structure or ownership, or participate in speculative trading. It also limits transactions with affiliates. Please see Note 15 for a description of management's retirement of this obligation. Funds available for advances under the credit agreement totaled $3.0 million at December 31, 2004.

(b) On February 15, 2005, concurrently with the closing of our initial public offering, we entered into a three-year $55.0 million senior secured revolving credit facility. MidFirst Bank, a federally chartered savings association located in Oklahoma City, Oklahoma, is a lender and serves as administrative agent under this facility. The credit facility consisted of a $47.5 million senior secured revolving credit facility to be used for funding acquisitions and other capital expenditures, issuance of letters of credit and general corporate purposes (the "revolving acquisition facility") and a $7.5 million senior secured revolving credit facility to be used for working capital and to fund distributions (the "revolving working capital facility").

On September 26, 2005, concurrently with the acquisition of Hiland Partners, LLC, we amended our senior secured revolving credit facility to increase our borrowing capacity under the facility from $55.0 million to $125.0 million, consisting of a $117.5 million acquisition facility and a $7.5 million working capital facility. On September 26, 2005, we incurred $93.7 million of indebtedness under the credit facility in connection with our acquisition of Hiland Partners, LLC. The credit facility will mature in February 2008. At that time, the agreement will terminate and all outstanding amounts thereunder will be due and payable.

Our obligations under the credit facility are collateralized by substantially all of our assets and guaranteed by us and all of our subsidiaries, other than our operating company, which is the borrower under the credit facility. The credit facility is non-recourse to our general partner.

Indebtedness under the credit facility will bear interest, at our option, at either (i) an Alternate Base Rate plus an applicable margin ranging from 50 to 175 basis points per annum or (ii) LIBOR plus an applicable margin ranging from 150 to 275 basis points per annum based on our ratio of total debt to EBITDA. The Alternate Base Rate is a rate per annum equal to the greatest of (a) the Prime Rate in effect on such day, (b) the base CD rate in effect on such day plus 1.50% and (c) the Federal Funds effective rate in effect on such day plus 1/2 of 1%. A letter of credit fee will be payable for the aggregate amount of letters of credit issued under the credit facility at a percentage per annum equal to 1.0%. An unused commitment fee ranging from 30 to 50 basis points per annum based on our ratio of total debt to EBITDA will be payable on the unused portion of the credit facility.

The credit facility imposes certain requirements, including: prohibition against distribution to unitholders if, before or after the distribution, a potential default or an event of default as defined in the agreement would occur; limitations on our ability to incur debt, grant liens, make loans, acquisitions, and investments, change the nature of our business, enter a merger or consolidation, or sell assets, amend material agreements; and covenants that require maintenance of certain levels of tangible net worth, EBITDA to interest expense ratio, and debt to EBITDA ratio. If an event of default exists under the agreement, the lenders will be able to accelerate the maturity of the debt and exercise other rights and remedies. As of September 30, 2005, we were in compliance with all of the covenants associated with our credit facility.

Maturities of long-term debt are as follows at December 31, 2004:

Year	Amount
2005	$ 2,429
2006	$ 12,643

Note 4: Lease Commitments

We lease office space from a related entity. See Note 8.

We lease certain facilities, pipelines and equipment under operating leases, most of which contain annual renewal options. For the years ended 2002, 2003 and 2004, rent expense was $292, $174 and $198, respectively, under these leases. At December 31, 2004, including leases renewed and entered into subsequent to year end but prior to financial statement issuance, the minimum future rental commitments under operating leases having non-cancelable lease terms in excess of one year, including leases from related parties, total:

Year	Amount
2005	$ 86
2006	92
2007	93
2008	92
2009	61
Thereafter	13
Total	$ 437

Note 5: Acquisitions

On September 26, 2005, we completed our acquisition of Hiland Partners, LLC, an Oklahoma limited liability company, for approximately $92.7 million in cash, $35.0 million of which was used to retire outstanding Hiland Partners, LLC indebtedness. The effective date of the acquisition was September 1, 2005. Hiland Partners, LLC's principal asset was the Bakken gathering system located in Richland County, Montana. The Bakken gathering system consists of approximately 256 miles of gas gathering pipeline, a natural gas processing plant, two compressor stations, which are comprised of three compressors with an aggregate of approximately 4,434 horsepower, and one fractionation facility. The Bakken processing plant and a portion of the gathering system became operational on November 8, 2004.

To facilitate the closing of the acquisition, we amended our senior secured revolving credit facility to increase our borrowing capacity under the facility from $55.0 million to $125.0 million, consisting of a $117.5 million acquisition facility and a $7.5 million working capital facility. The credit facility's maturity date remained the same, February 15, 2008. The current interest rate ranges from LIBOR plus 150 to 275 basis points depending on leverage coverage. We used a portion of this increased capacity to fund the acquisition.

To the extent of our non-controlling ownership, the acquisition was accounted for using the purchase method of accounting under SFAS No. 141, "Business Combinations." As of the date of our acquisition, Hiland Partners, LLC was an entity partially owned by a controlling member of our general partner. Accordingly, 49% of the Bakken gathering system assets, for which estimated fair value was in excess of historical basis, have been recorded at historical cost and 51% of the Bakken gathering system assets have been recorded at fair value. A cash distribution of $27.8 million made to the controlling member as reported in the statement of owners' equity reflects the difference in the purchase price paid to the controlling member of our general partner and his cost basis in the net assets of Hiland Partners, LLC. The fair value of the assets acquired has also been reduced by imputed interest expense from September 1, 2005, the effective date of the acquisition, through the closing date, September 26, 2005. The following table presents the resulting allocation to the net assets acquired and liabilities assumed at the effective date of acquisition:

Cash and cash equivalents	$ 300
Accounts receivable	3,708
Other assets	20
Property, plant and equipment	49,643
Customer contracts, customer relationships and right of way	17,589
Total net assets acquired	71,260
Accounts payable	(6,217)
Accrued liabilities	(125)
Total liabilities assumed	(6,342)
Net assets of Hiland Partners, LLC	64,918
Imputed interest expense	(289)
Purchase price of net assets of Hiland Partners, LLC	$ 64,629

On July 31, 2003, we acquired the Carmen Gathering System ("Carmen") located in western Oklahoma from Great Plains Pipeline Company for $15.0 million. After various adjustments and other reductions in the purchase and sale agreement, the net cost was $12.0 million. Funding for the acquisition was obtained under our credit agreement with CRI. The allocation of the purchase price was based on fair values of the assets as follows:

	Amount
Land	$ 120
Pipeline	11,833
Other equipment	72
Total	$ 12,025

The operations of Carmen are included in the statement of operations and statement of cash flows from August 1, 2003 forward.

The unaudited pro forma information set forth below includes the operations of Carmen assuming the acquisition of Carmen by CGI occurred on January 1, 2003. The unaudited pro forma information is presented for information only and is not necessarily indicative of the results of operations that actually would have been achieved had the acquisition be consummated at that time:

	Pro Forma For the Twelve Months Ended December 31, 2003		
	Carmen For the Seven Months Ended July 31, 2003	CGI For the Year Ended December 31, 2003	Consolidated
Midstream revenue	$ 14,534	$ 76,018	$ 90,552
Total operating costs and expenses:			
Midstream purchases (exclusive of items shown separately below)	12,160	67,002	79,162
Operations and maintenance	462	3,714	4,176
Property impairment		1,535	1,535
Depreciation and amortization	414	3,304	6,223
Loss on asset sales		34	34
General and administrative	128	770	898
Total operating costs and expenses	13,164	76,359	92,028
Income (loss) from operations	1,370	(341)	(1,476)
Other income (expense):			
Interest and other income		10	10
Amortization of deferred loan costs		(24)	(24)
Interest expense	(281)	(473)	(473)
Total other income (expense)	(281)	(487)	(487)
Income (loss) from continuing operations	1,089	(828)	(1,963)
Discontinued operations, net		246	246
Income (loss) before cumulative effect of change in accounting principle	1,089	(582)	(1,717)
Cumulative effect of change in accounting principle		1,554	1,554
Net income (loss)	$ 1,089	$ 972	$ (163)

Note 6: Commitments and Contingencies

As a part of the Carmen acquisition discussed in Note 5, we became obligated to issue a letter of credit in the amount of $1.5 million to a customer of Carmen. This letter of credit was maintained in force through January 2005. No advances or demands have been made against the letter of credit.

We have executed fixed price physical forward sales contracts on approximately 50,000 MMBtu per month through December 2007 with weighted average fixed prices per MMBtu of $4.53, $4.47 and $4.49, respectively, for years 2005 through 2007. We also have fixed price physical forward sales contracts to sell approximately 50,000 MMBtu of natural gas per month from October 2005 through December 2006 with weighted average fixed prices per MMBtu of $9.52. Such contracts have been designated as normal sales under SFAS No. 133 and are therefore not marked to market as derivatives.

We maintain a defined contribution retirement plan for our employees under which we make discretionary contributions to the plan based on a percentage of eligible employees compensation. During 2002, 2003 and 2004 and the nine months ended September 30, 2005, contributions to the plan were 5.0% of eligible employees' compensation. Expense for the years ended December 31, 2002, 2003 and 2004 was $45, $54, and $70, respectively. Expense for the nine months ended September 30, 2004 and 2005 was $53 and $72, respectively.

The Partnership and other affiliated companies participate jointly in a self-insurance pool (the "Pool") covering health and workers' compensation claims made by employees up to the first $150 and $500, respectively, per claim. Any amounts paid above these are reinsured through third party providers. Premiums charged to the Partnership are based on estimated costs per employee of the Pool. No additional premium assessments are anticipated for periods prior to September 30, 2005. Property and general liability insurance is maintained through third-party providers with a $100 deductible on each policy.

We are a party to various regulatory proceedings and may from time to time be a party to litigation that we believe will not have a materially adverse impact on our financial condition, results of operations or cash flows.

The operation of pipelines, plants and other facilities for gathering, compressing, treating, or processing natural gas, NGLs and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. Our management believes that compliance with federal, state or local environmental laws and regulations will not have a material adverse effect on our business, financial position or results of operations.

Note 7: Significant Customers and Suppliers

All revenues are domestic revenues. The following table presents our top midstream customers as a percent of total revenue for the periods indicated:

	For the Year Ended December 31,			For the Nine Months Ended September 30,
	2002	2003	2004	2005
Customer 1	32%	17%		
Customer 2	22%	19%	29%	25%
Customer 3	12%	9%	5%	4%
Customer 4	10%	7%	10%	6%
Customer 5		28%	33%	19%
Customer 6				9%
Customer 7				7%

All purchases are from domestic sources. The following table presents our top midstream suppliers as a percent of total midstream purchases for the periods indicated:

	For the Year Ended December 31,			For the Nine Months Ended September 30,
	2002	2003	2004	2005
Supplier 1 (affiliated company)	43%	37%	33%	33%
Supplier 2	21%	20%		
Supplier 3		18%	17%	13%
Supplier 4			33%	32%

Note 8: Related Party Transactions

We purchase natural gas and NGLs from affiliated companies. Purchases of product totaled $13.3 million, $26.2 million, and $27.6 million for the years ended December 31, 2002, 2003 and 2004, respectively. Purchases of product totaled $20.3 million and $26.8 million for the nine months ended September 30, 2004 and 2005, respectively. We sell natural gas and NGLs to affiliated companies. Sales of product totaled $1.4 million, $2.4 million, and $3.3 million for the years ended December 31, 2002, 2003 and 2004, respectively. Sales of product totaled $2.3 million and $3.5 million for the nine months ended September 30, 2004 and 2005, respectively. Compression revenues from affiliates were $0 and $3.0 million for the nine months ended September 30, 2004 and 2005, respectively.

Accounts receivable affiliates of $532 and $758 at December 31, 2003 and 2004, respectively, includes $459 and $682 from one affiliate for midstream sales. Accounts receivable affiliates of $1,107 at September 30, 2005 includes $1,102 from the same affiliate for midstream sales.

Accounts payable affiliates of $2,814 at December 31, 2003 includes $2,567 due to one affiliate for midstream purchases. Accounts payable affiliates of $2,998 at December 31, 2004 is all payable to one affiliate for midstream purchases. Accounts payable affiliates of $7,660 at September 30, 2005 includes $5,258 due to the same affiliate for midstream purchases. Also included in accounts payable to affiliates at September 30, 2005 is $2,119 payable to the prior owners of Hiland Partners, LLC in connection with the Bakken acquisition.

We utilize affiliated companies to provide services to its plants and pipelines and certain administrative costs. The total amount paid to these companies was $142, $193, and $183 during the years ended December 31, 2002, 2003 and 2004, respectively. Amounts paid to affiliates for services were $127 and $74 for the nine months ended September 30, 2004 and 2005, respectively.

We lease office space under operating leases directly or indirectly from an affiliate. Rents paid associated with these leases totaled $31, $47, and $51 for the years ended December 31, 2002, 2003 and 2004, respectively. Rents paid to affiliates were $32 and $57 for the nine months ended September 30, 2004 and 2005, respectively.

Note 9: Business Segments

On February 15, 2005, certain assets and liabilities of Hiland Partners, LLC were contributed to us in conjunction with our initial public offering. As a result of this transaction, we have distinct operating segments for which additional financial information must be reported. Prior to February 15, 2005, we did not have operating segments. Our operations are now classified into two reportable segments:

(1) Midstream, which is the gathering, compressing, dehydrating, treating and processing of natural gas and fractionating NGLs.

(2) Compression, which is providing air compression and water injection services for CRI's oil and gas secondary recovery operations that are ongoing in North Dakota.

We evaluate the performance of our segments and allocate resources to them based on operating income. Our operations are conducted in the United States.

Midstream assets totaled $150,649 at September 30, 2005. Assets attributable to compression operations totaled $35,902. Excluding the Bakken acquisition, $2,759 of the total $2,770 capital expenditures for the nine months ended September 30, 2005 were related to the midstream segment. The tables below present information about operating income for the reportable segments for the nine months ended September 30, 2005.

	Nine Months Ended September 30, 2005		
	Midstream	Compression	Total
Revenues	$ 95,294	$ 3,012	$ 98,306
Operating costs and expenses:			
Midstream purchases (exclusive of items shown separately below)	77,548		77,548
Operations and maintenance	4,712	371	5,083
Depreciation, amortization and accretion	4,697	2,227	6,924
General and administrative	1,492	47	1,539
Total operating costs and expenses	88,449	2,645	91,094
Income from operations	$ 6,845	$ 367	7,212
Other income (expense):			
Interest and other income			112
Amortization of deferred loan costs			(360)
Interest expense			(766)
Total other income (expense)			(1,014)
Net income			$ 6,198

Note 10: Discontinued Operations

During the first quarter of 2004, the Partnership determined it would no longer pursue its interests in direct production of oil and gas. Amounts for oil and gas income and expense are presented in these statements as discontinued operations. Effective May 31, 2004, the Partnership transferred all its interests in its oil and gas properties to CRI.

A summary of oil and gas operations follows:

	Year Ended December 31,		
	2002	2003	2004
Revenues	$ 591	$ 604	$ 266
Expenses	(188)	(351)	(165)
Depreciation, amortization and accretion	(140)	(170)	(66)
Loss on assets sales	(64)	(7)	
Change in accounting principle		170	
Net income	$ 199	$ 246	$ 35
Net Assets	$ 1,658	$ 2,452	$
Associated Liabilities	$ 81	$ 235	$

The transfer, recorded at carrying value, included the following:

	Amount
Leasehold costs	$ 67
Capitalized intangible costs	3,063
Lease and well equipment	1,689
Asset retirement cost	41
Accounts payable	(298)
Accumulated amortization	(1,623)
Accumulated depreciation	(748)
Asset retirement obligation	(50)
	$ 2,141

The Partnership followed the "successful efforts" method of accounting for its oil and gas properties. Under the successful efforts method, costs of acquiring undeveloped oil and gas leasehold acreage, including lease bonuses, brokers' fees and other related costs are capitalized. Provisions for impairment of undeveloped oil and gas leases are based on periodic evaluations. Annual lease rentals and exploration expenses, including geological and geophysical expenses and exploratory dry hole costs, are charged against income as incurred. Costs of drilling and equipping productive wells, including development dry holes and related production facilities, are capitalized. Depreciation and depletion of oil and gas production equipment and properties are determined under the unit-of-production method based on estimated proved recoverable oil and gas reserves.

Note 11: Selected Quarterly Financial Data Unaudited

The following is a summary of selected quarterly financial data for the years ended December 31, 2003 and 2004 and the nine months ended September 30, 2005:

	2003 Quarter			
	1st	2nd	3rd	4th
Revenues	$ 12,004	$ 16,355	$ 23,407	$ 24,252
Operating income (loss)	108	405	(139)	(715)
Income (loss) from continuing operations	50	340	(314)	(904)
Income (loss) before cumulative effect of change in accounting principle	121	512	(288)	(927)
Net income (loss)	1,675	512	(288)	(927)

	2004 Quarter			
	1st	2nd	3rd	4th
Revenues	$ 21,050	$ 23,849	$ 25,387	$ 28,010
Operating income	933	1,126	1,089	2,493
Income from continuing operations	752	937	898	2,290
Income before cumulative effect of change in accounting principle	767	1,008	846	2,291
Net income	767	1,008	846	2,291

	2005 Quarter		
	1st	2nd	3rd
Revenues	$ 25,778	$ 30,603	$ 41,925
Operating income	1,968	1,962	3,282
Net income	1,636	1,879	2,684
Income attributable to predecessor	493		
General partner interest in net income	23	37	67
Limited partners' interest in net income	$ 1,120	$ 1,842	$ 2,617
Net income per limited partner unit basic and diluted	$ 0.16	$ 0.27	$ 0.38

Note 12: Net Income per Limited Partners' Unit

The computation of net income per limited partners' unit is based on the weighted-average number of common and subordinated units outstanding during the period. Net income per unit applicable to limited partners is computed by dividing net income applicable to limited partners, after deducting the general partner's 2% interest and incentive distributions, and after deducting net income attributable to the Predecessor (before February 15, 2005), by the weighted-average number of limited partnership units outstanding. The following is a reconciliation of the limited partner units used in the calculations of income per limited partner unit basic and income per limited partner unit diluted assuming dilution for the nine months ended September 30, 2005:

	Income Available to Limited Partners (Numerator)	Limited Partner Units (Denominator)	Per Unit Amount
For the nine months ended September 30, 2005:			
Income per limited partner unit basic:			
Income available to limited unitholders	$ 5,577		$ 0.82
Weighted average limited partner units outstanding		6,800,000	
Income per limited partner unit diluted:			
Unit Options		30,000	
Income available to common unitholders plus assumed conversions	$ 5,577	6,830,000	$ 0.82

Note 13: Initial Formation and Contribution of Assets

In connection with our formation and our initial public offering on February 15, 2005, the assets and liabilities of CGI excluding certain working capital assets were contributed to us in exchange for 271,082 of our common units and 2,646,749 of our subordinated units. Existing bank debt of CGI was repaid from the proceeds of our initial public offering.

All of our initial assets were contributed by the former owners of CGI, Hiland Partners, LLC, and certain affiliates, including our general partner, in exchange for an aggregate of 720,000 common units and 4,080,000 subordinated units, a 2% general partner interest in us and all of our incentive distribution rights, which entitle the general partner to increasing percentages of the cash we distribute in excess of $0.495 per unit per quarter. The assets of GCI transferred to us are recorded at historical cost as it is considered to be a reorganization of entities under common control and CGI is considered our accounting predecessor. The acquisition of the assets of Hiland Partners, LLC was accounted for as a purchase and, as a result, these assets were recorded at their fair value at the time of purchase.

The following table presents the assets and liabilities of our predecessor immediately prior to contributing assets to us, assets and liabilities contributed to us, and our predecessor's assets and liabilities not contributed to us.

Continental Gas, Inc. (Predecessor)
Assets Contributed to Hiland Partners, LP
As of February 14, 2005
(unaudited)

	Continental Gas, Inc. (Predecessor) February 14, 2005	Net Assets Not Contributed	Contributed to Hiland Partners, February 15, 2005
ASSETS			
Current assets:			
Cash and cash equivalents	$ 869	$ 869	$
Accounts Receivable	10,521	9,101	1,420
Inventories	153		153
Other current assets	291	2	289
Total current assets	11,834	9,972	1,862
Property and equipment, at cost, net	36,805		36,805
Other assets, net	3,388		3,388
Total assets	52,027	9,972	42,055
LIABILITIES			
Current liabilities:			
Accounts payable	11,703		11,703
Accrued liabilities	700		700
Current maturities of long term debt	2,429		2,429
Total current liabilities	14,832		14,832
Commitments and contingencies			
Long term debt, net of current maturities	11,570		11,570
Asset retirement obligation	622		622
Total liabilities	27,024		27,024
NET ASSETS	$ 25,003	$ 9,972	$ 15,031

In consideration for the transfer, Harold Hamm and the Hamm Trusts received 467,073 of our common units and 2,646,749 of our subordinated units. Immediately following the closing of the offering, 195,991 of the common units were redeemed for approximately $4.1 million.

The following table presents the assets and liabilities of Hiland Partners, LLC as of February 14, 2005, the assets excluded from the acquisition, and the fair value of the assets acquired.

Hiland Partners, LLC
Assets Contributed to Hiland Partners, LP
As of February 14, 2005
(unaudited)

	Hiland Partners, LLC February 14, 2005	Net Assets Not Contributed	Assets Contributed to Hiland Partners, LP February 15, 2005	Fair Value
ASSETS				
Current assets:				
Cash and cash equivalents	$ 964	$ 964	$	$
Accounts Receivable	2,619	2,503	116	116
Other current assets	56	10	46	46
Total current assets	3,639	3,477	162	162
Property and equipment, at cost, net	50,063	29,858	20,205	31,600
Intangible assets				26,800
Other assets, net	194	89	105	105
Total assets	53,896	33,424	20,472	58,667
LIABILITIES				
Current liabilities:				
Accounts payable	5,048	4,372	676	676
Accrued liabilities	95	30	65	65
Current maturities of long term debt	11,100	2,221	8,879	8,879
Total current liabilities	16,243	6,623	9,620	9,620
Commitments and contingencies				
Long term debt, net of current maturities	24,253	24,253		
Asset retirement obligation	397		397	397
Total liabilities	40,893	30,876	10,017	10,017
NET ASSETS	$ 13,003	$ 2,548	$ 10,455	$ 48,650

In consideration for the transfer:

a. Non-managing members received 247,868 of our common units and 1,404,586 of our subordinated units. Immediately following the closing of the offering, 104,009 of the common units were redeemed for approximately $2.2 million.

b. The managing member of Hiland Partners, LLC received 5,059 of our common units and 28,665 of our subordinated units, none of which were redeemed.

As a part of the transactions, owners of CGI, Hiland Partners, LLC and certain members of our management received an aggregate of 138,776 equivalent units of our General Partner, representing substantially all of the ownership of the general partner and a 2% equity ownership in us.

The proceeds of the public offering were used to: redeem an aggregate of 300,000 common units from former owners for $6.3 million; repay $14.0 million in debt owed by CGI and $8.9 million in debt contributed from Hiland Partners, LLC; pay the remaining $2.2 million of expenses associated with the offering and formation transactions; pay $0.6 million of debt issuance costs related to the credit facility; distribute $3.9 million to the former owners of Hiland Partners, LLC in reimbursement of certain capitalized expenditures related to the assets of Hiland Partners, LLC that were contributed to us; and replenish approximately $12.2 million of working capital.

Note 14: Pro Forma Operations

The acquisition of Hiland Partners, LLC discussed in note 5 was effective September 1, 2005 and the initial acquisition of assets from Hiland Partners, LLC discussed in note 13 occurred on February 15, 2005. Had the acquisitions been made effective January 1, 2004, the operations of the assets acquired from Hiland Partners, LLC would have been included in our consolidated financial statements for each subsequent period with the following unaudited pro forma impact on the consolidated statements of operations. The pro forma financial information is not necessarily indicative of the results of operations as it would have been had these transactions been effected on the assumed dates.

	Year Ended December 31, 2004	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2005
	(in thousands)		
Revenues as reported	$ 98,296	$ 70,286	$ 98,306
Revenues from Hiland Partners, LLC	14,335	8,941	18,649
Pro forma revenues	$ 112,631	$ 79,227	$ 116,955
Net income from continuing operations as reported	$ 4,877	$ 2,621	$ 6,198
Income (loss) from acquired interest	(3,456)	(1,860)	(4,176)
Pro forma net income	$ 1,421	$ 761	2,022
Less income attributable to predecessor			493
Less general partner interest in proforma net income			41
Limited partners' interest in proforma net income			$ 1,488
Proforma net income per limited partner unit, basic			$ 0.22
Proforma net income per limited partner unit, diluted			0.22
Weighted average limited partner units outstanding, basic			6,800,000
Weighted average limited partner units outstanding, diluted			6,830,000

Note 15: Partners' capital

Our Partnership Agreement requires that we distribute all of our cash on hand at the end of each quarter, less reserves established at our general partner's discretion. We refer to this as "available cash." The amount of available cash may be greater than or less than the minimum quarterly distributions. In general, we will pay any cash distribution made each quarter in the following manner:

- first, 98% to the common units and 2% to our general partner, until each common unit has received a minimum quarterly distribution of $0.45 plus any arrearages from prior quarters;

- second, 98% to the subordinated units and 2% to our general partner, until each subordinated unit has received a minimum quarterly distribution of $0.45; and

- third, 98% to all units pro rata, and 2% to our general partner, until each unit has received a distribution of $0.495.

If cash distributions per unit exceed $0.495 in any quarter, our general partner will receive increasing percentages, up to a maximum of 50% of the cash we distribute in excess of that amount. We refer to these distributions as "incentive distributions."

The distributions on the subordinated units may be reduced or eliminated if necessary to ensure the common units receive their minimum quarterly distribution. Subordinated units will not accrue arrearages. The subordination period will end once we meet certain financial tests, but not before March 31, 2010. These financial tests require us to have earned and paid the minimum quarterly distribution on all of our outstanding units for three consecutive four-quarter periods. When the subordination period ends, all remaining subordinated units will convert into common units on a one-for-one basis, and the common units will no longer be entitled to arrearages.

On April 25, 2005, we announced our first regular cash distribution in 2005 of $0.225 per unit, based on the minimum quarterly cash distribution of $0.45 prorated for the period since the initial public offering on February 15, 2005. The distribution to all common, subordinated and general partner units was paid May 13, 2005, to all unitholders of record on May 5, 2005. The aggregate amount of the distribution was $1.6 million.

On July 26, 2005, we announced a regular cash distribution of $0.4625 per unit for the second quarter of 2005. The distribution to all common, subordinated and general partner units was paid on August 12, 2005 to all unitholders of record on August 5, 2005. The aggregate amount of the distribution was $3.2 million.

Note 16: Restricted Units

During the quarter ended September 30, 2005 we issued 8,000 restricted common units to non-employee board members of our general partner. We have recorded $324 as unearned compensation in owners' equity based on the fair market value of the units on the date of grant. The restricted units vest over a four year period from the date of issuance. Periodic distributions on the restricted units will be held in trust by our general partner until the units vest. As a result of the additional restricted common units issued our general partner contributed $6 to us to maintain its 2% ownership.

Note 17: Subsequent Events

On October 25, 2005, we announced a regular cash distribution of $0.5125 per unit for the third quarter of 2005. The distribution to all common, subordinated and general partner units is payable on November 14, 2005 to all unitholders of record on November 4, 2005. The aggregate amount of the distribution will be $3.5 million. As provided for in our Partnership Agreement, our general partner is entitled to receive increasing percentages, up to a maximum of 50% of the cash distributed in excess of $0.495 in any quarter as "incentive distributions." This distribution of $0.5125 per unit exceeds the $0.495 per unit by $0.0175. Accordingly, our general partner will receive an additional 15% of the excess, or $21.

In October 2005, we executed swap contracts relating to a portion of our residue gas sales from our Bakken gathering system for the fixed prices noted below. Under these swap contracts, we will either pay or receive the difference between the fixed prices below and the Colorado Interstate Gas (CIG) index price. As a result, we have hedged a portion of our expected exposure to natural gas prices in 2006 and 2007 at the Bakken gathering system. The following table provides information about these financial derivative instruments:

Natural Gas Swaps	**Monthly Volume (MMBtu)**		**Price ($/MMBtu)**
May 2006-December 2006	40,000	$	8.78
January 2007-October 2007	40,000	$	7.83

We intend to offer additional common units, representing limited partner interests, pursuant to a public offering. We intend to use the net proceeds from such offering to repay a portion of the outstanding indebtedness incurred to fund our recent acquisition of Hiland Partners, LLC.

On November 8, 2005, we entered into a new 15-year definitive gas purchase agreement with Continental Resources, Inc. under which we will gather, treat and process additional natural gas, which is produced as a by-product of Continental Resources' secondary oil recovery operations, in the areas specified by the contract. In return, we will receive 50% of the proceeds attributable to residue gas and natural gas liquids as well as certain fixed fees associated with gathering and treating the natural gas. In order to fulfill our obligations under the agreement, we intend to expand our Badlands gas gathering system and processing plant located in Bowman County, North Dakota. This expansion project will include the construction of a 40,000 Mcf/d nitrogen rejection plant and the expansion of our existing Badlands field gathering infrastructure. The expansion project, which is targeted for completion in the fourth quarter of 2006, is expected to cost approximately $40.0 million, which we intend to fund using our existing bank credit facility. Moreover, we expect to spend an additional $9.5 million in 2007 to expand the system.

Report of Independent Registered Public Accounting Firm

Members
Hiland Partners, LLC

We have audited the accompanying combined statements of net assets acquired from Hiland Partners, LLC by Hiland Partners, LP (the reporting entity) as of December 31, 2003 and 2004, and the related combined statements of operations and changes in net assets, and cash flows for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with 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 reporting entity 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 reporting entity'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 combined financial statements referred to above present fairly, in all material respects, the net assets acquired from Hiland Partners, LLC as of December 31, 2003 and 2004, and the results of operating activities and cash flows of net assets acquired from Hiland Partners, LLC for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the combined financial statements effective January 1, 2003, Statement of Financial Accounting Standards No. 143 was adopted and changed the method of accounting for asset retirement obligations.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 15, 2005

COMBINED STATEMENTS OF NET ASSETS ACQUIRED FROM HILAND PARTNERS, LLC

	December 31, 2003	December 31, 2004	June 30, 2005
			(unaudited)
		(in thousands)	
ASSETS			
Current assets:			
Cash and cash equivalents	$ 490	$ 770	$ 633
Accounts receivable:			
Trade	659	1,863	2,513
Affiliates	335	579	20
	994	2,442	2,533
Other current assets	1	67	32
Total current assets	1,485	3,279	3,198
Property and equipment, at cost, net	21,973	48,295	35,080
Other assets, net		118	78
Total assets	23,458	51,692	38,356
LIABILITIES			
Current liabilities:			
Accounts payable	$ 602	$ 5,530	$ 3,482
Accounts payable-affiliates	2	415	591
Accrued liabilities		153	116
Current maturities of long-term debt	3,336	9,356	33,500
Total current liabilities	3,940	15,454	37,689
Commitments and contingencies			
Long-term debt, net of current maturities	10,830	23,279	
Asset retirement obligation	381	396	
Total liabilities	15,151	39,129	37,689
NET ASSETS	$ 8,307	$ 12,563	$ 667

The accompanying notes are an integral part of the financial statements.

COMBINED STATEMENTS OF OPERATIONS AND CHANGES IN NET ASSETS ACQUIRED FROM HILAND PARTNERS, LLC

	Year Ended December 31,			Six Months Ended June 30,	
	2002	2003	2004	2004	2005
				(unaudited)	
			(in thousands)		
Revenues:					
Midstream operations					
Third parties	$ 4,839	$ 6,372	$ 9,379	$ 3,412	$ 11,319
Affiliates	641	890	1,102	417	389
Compressor lease income, affiliate	244	3,300	3,854	1,929	336
Total revenues	5,724	10,562	14,335	5,758	12,044
Operating costs and expenses:					
Midstream purchases (exclusive of items shown separately below)	842	1,689	2,795	639	5,402
Midstream purchases affiliate (exclusive of items shown separately below)	597	1,137	1,805	681	2,885
Operations and maintenance	1,779	1,900	2,080	911	1,292
Depreciation, amortization and accretion	522	1,684	2,311	1,026	1,384
Loss on asset sales	36				
General and administrative	156	101	97	37	36
Total operating costs and expenses	3,932	6,511	9,088	3,294	10,999
Operating income	1,792	4,051	5,247	2,464	1,045
Other income (expense):					
Interest and other income	27	11	1	1	3
Amortization of deferred loan costs	(73)		(106)	(2)	(49)
Interest expense (affiliate in 2002)	(232)	(574)	(661)	(271)	(880)
Total other expense	(278)	(563)	(766)	(272)	(926)
Income before change in accounting principle	1,514	3,488	4,481	2,192	119
Cumulative effect of change in accounting principle		(73)			
Net income	$ 1,514	$ 3,415	$ 4,481	$ 2,192	$ 119
Beginning net assets	$ 3,808	$ 4,892	$ 8,307	$ 8,307	$ 12,563
Distributions	(430)		(225)	(65)	(12,015)
Net income	1,514	3,415	4,481	2,192	119

	Year Ended December 31,			Six Months Ended June 30,	
Ending net assets	$ 4,892	$ 8,307	$ 12,563	$ 10,434	$ 667

The accompanying notes are an integral part of the financial statements.

COMBINED STATEMENTS OF CASH FLOWS OF NET ASSETS ACQUIRED FROM HILAND PARTNERS, LLC

	Year Ended December 31,			Six Months Ended June 30,	
	2002	2003	2004	2004	2005
				(unaudited)	
			(in thousands)		
Cash flows from operating activities:					
Net income	$ 1,514	$ 3,415	$ 4,481	$ 2,192	$ 119
Adjustments to reconcile net income to net cash provided by operating activities:					
Cumulative effect of change in accounting principle		73			
Depreciation and amortization	522	1,669	2,296	1,019	1,432
Amortization of deferred loan cost	73		106	2	
Change in asset retirement obligation		15	15	7	1
Loss on sale of assets	36				
(Increase) decrease in current assets:					
Accounts receivable	1,223	(99)	(1,204)	(19)	(766)
Accounts receivable affiliates	(406)	71	(244)	7	559
Other current assets	(1)		(66)		(10)
Increase (decrease) in current liabilities:					
Accounts payable	45	220	1,091	(274)	(1,430)
Accounts payable affiliates	(16)	1	413	23	176
Accrued liabilities	(10)	(3)	153	23	72
Net cash provided by operating activities	2,980	5,362	7,041	2,980	153
Cash flows from investing activities:					
Additions to property and equipment	(12,528)	(5,114)	(24,781)	(280)	(8,371)
Additions to construction in progress				(2,010)	
Proceeds from disposals of properties and equipment	426				
Net cash used in investing activities	(12,102)	(5,114)	(24,781)	(2,290)	(8,371)
Cash flows from financing activities:					
Repayments to affiliates	(3,495)				
Increase in deferred loan costs	(73)		(160)	(50)	
Borrowings from third parties	14,500	4,404	50,384		10,221
Repayments of borrowings	(900)	(4,738)	(31,915)	(316)	(477)
Increase in deferred offering costs			(64)		(114)
Distributions to owners	(430)		(225)	(65)	(1,549)
Net cash provided by (used in) financing activities	9,602	(334)	18,020	(431)	8,081
Cash and cash equivalents:					
Increase (decrease) for the period	480	(86)	280	259	(137)
Beginning of period	96	576	490	490	770
End of period	$ 576	$ 490	$ 770	$ 749	$ 633

	Year Ended December 31,			Six Months Ended June 30,	
Supplementary information:					
Cash paid for interest, net of amounts capitalized	$ 232	$ 574	$ 616	$ 270	$ 830
Effective January 1, 2003 the company recorded the cumulative effect of SFAS No 143 for asset retirement obligation as follows:					
Increase in property and equipment		$ 293			
Increase in asset retirement obligation		(366)			
Cumulative effect of accounting change		$ (73)			

The accompanying notes are an integral part of the financial statements.

NOTES TO COMBINED FINANCIAL STATEMENTS
OF NET ASSETS ACQUIRED FROM HILAND PARTNERS, LLC

(Information as of June 30, 2005 and for the Six Months Ended June 30, 2004 and 2005 is Unaudited)
(in thousands, unless otherwise noted)

Note 1: Description of Business, Basis of Presentation and Summary of Significant Accounting Policies

Description of Business

Hiland Partners, LLC ("Hiland") was formed in September 2000 as an Oklahoma limited liability company. Hiland operates in two businesses: midstream, which is engaged in the gathering, compressing, dehydrating, treating, processing and marketing of natural gas and fractionating natural gas liquids, or NGLs; and compression, which is engaged in providing air compression and water injection services for oil and gas secondary recovery operations that are ongoing in North Dakota.

Hiland connects the wells of natural gas producers in its market area to its gathering system, treats natural gas to remove impurities, processes natural gas for the removal of NGLs and sells the resulting products to a variety of intermediate purchasers. Hiland owns and operates one processing plant with associated compressor stations, fractionation facilities and approximately 150 miles of gathering pipeline in Wyoming and commenced operations of another processing plant and gathering system in Montana in November 2004.

Hiland leases several large compressors to an affiliated entity, Continental Resources, Inc. ("CRI"). Certain Hiland owners also own approximately 9% of CRI common stock. These compressors supply compressed air and water for use in a secondary oil recovery project in North Dakota for which CRI is the operator.

The accompanying combined financial statements present the net assets and operations of the Worland gathering system, compression facilities and water injection plant acquired by Hiland Partners, LP on February 15, 2005, and the net assets and operations of the Bakken gathering system acquired by Hiland Partners, LP on September 26, 2005, effective as of September 1, 2005.

The unaudited interim financial statements reflect all adjustments, which are in the opinion of management, necessary for a fair presentation of the results for the interim periods of the net assets acquired. Such adjustments are considered to be of a normal recurring nature. Results of operating activities for the six months ended June 30, 2005 are not necessarily indicative of the results of operating activities that will be realized for the year ending December 31, 2005.

Principles of Combination

The combined financial statements include the net assets acquired from Hiland Partners, LLC and its wholly owned subsidiary Hiland Energy Partners, LLC (collectively, "the Company"). All significant intercompany accounts have been eliminated.

Use of Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates.

Cash and Cash Equivalents

The Company considers all highly liquid investments with maturity of three months or less at the time of purchase to be cash equivalents.

Accounts Receivable

The majority of the accounts receivable are due from companies in the oil and gas industry as well as the utility industry. Credit is extended based on evaluation of the customer's financial condition. In certain circumstances, collateral, such as letters of credit or guarantees, is required. Accounts receivable are due within 30 days and are stated at amounts due from customers. The Company has established various procedures to manage its credit exposure, including initial credit approvals, credit limits and rights of offset. Credit losses are charged to income when accounts are deemed uncollectible, determined on a case-by-case basis when the Company believes the required payment of specific amounts owed is unlikely to occur. These losses historically have been minimal, therefore, an allowance for uncollectible accounts is not required.

Concentration and Credit Risk

Financial instruments that potentially subject the Company to concentrations of credit risk consist principally of cash and cash equivalents and receivables.

The Company places its cash and cash equivalents with high-quality institutions and in money market funds. The Company derives its revenue from customers primarily in the natural gas and utility industries. These industry concentrations have the potential to impact the Company's overall exposure to credit risk, either positively or negatively, in that the Company's customers could be affected by similar changes in economic, industry or other conditions. However, the Company believes that the credit risk posed by this industry concentration is offset by the creditworthiness of the Company's customer base. The Company's portfolio of accounts receivable is comprised primarily of mid-size to large domestic corporate entities.

Fair Value of Financial Instruments

The Company's financial instruments, which require fair value disclosure, consist primarily of cash and cash equivalents, accounts receivable, accounts payable and bank debt. The carrying value of cash and cash equivalents, accounts receivable and accounts payable are considered to be representative of their respective fair values, due to the short maturity of these instruments. The fair value of long-term debt approximates its carrying value due to the variable interest rate feature of such debt.

Long-Lived Assets

In accordance with Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," the Company evaluates its long-lived assets of identifiable business activities for impairment when events or changes in circumstances indicate, in management's judgment, that the carrying value of such assets may not be recoverable. The determination of whether impairment has occurred is based on management's estimate of undiscounted future cash flows attributable to the assets as compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value for the assets and recording a provision for loss if the carrying value is greater than fair value. For assets identified to be disposed of in the future, the carrying value of these assets is compared to the estimated fair value less the cost to sell to determine if impairment is required. Until the assets are disposed of, an estimate of the fair value is re-determined when related events or circumstances change.

When determining whether impairment of a long-lived asset has occurred, the Company must estimate the undiscounted cash flows attributable to the asset or asset group. The estimate of cash flows is based on assumptions regarding the volume of reserves providing asset cash flow and future NGL product and natural gas prices. The amount of reserves and drilling activity are dependent in part on natural gas prices. Projections of reserves and future commodity prices are inherently subjective and contingent upon a number of variable factors, including, but not limited to:

- changes in general economic conditions in regions in which the Company's products are located;
- the availability and prices of NGL products and competing commodities;
- the availability and prices of raw natural gas supply;
- the Company's ability to negotiate favorable marketing agreements;
- the risks that third party oil and gas exploration and production activities will not occur or be successful;
- the Company's dependence on certain significant customers and producers of natural gas; and
- competition from other midstream service providers and processors, including major energy companies.

Any significant variance in any of the above assumptions or factors could materially affect the Company's cash flows, which could require the Company to record an impairment of an asset.

Hiland does not believe any asset impairment has occurred and, accordingly, has not recognized any impairment charges in these financial statements.

Revenue Recognition

Revenues for sales of natural gas and NGLs are recognized at the time all gathering and processing activities are completed, the product is delivered and title is transferred. Revenues from compressor leasing operations are recognized when earned ratably as due under the lease.

Property and Equipment

The Company's property and equipment are carried at cost. Depreciation and amortization of all equipment is determined under the straight-line method using various rates based on useful lives, 14 to 20 years for pipeline and processing plants, 10 years for compressors and associated equipment and 3 to 10 years for corporate and other assets. The cost of assets and related accumulated depreciation is removed from the accounts when such assets are disposed of, and any related gains or losses are reflected in current earnings. Maintenance, repairs and minor replacements are expensed as incurred. Costs of replacements constituting improvement are capitalized.

Environmental Costs

Environmental costs are expensed if they relate to an existing condition caused by past operations and do not contribute to current or future revenue generation. Liabilities are recorded when site restoration and environmental remediation and cleanup obligations are either known or considered probable and can be reasonably estimated. Recoveries of environmental costs through insurance, indemnification arrangements or other sources are included in other assets to the extent such recoveries are considered probable.

Income Taxes

As a limited liability company electing to be taxed as a partnership, Hiland is not subject to income taxes. Accordingly, taxable income of Hiland is allocated to the members who are responsible for payment of any income taxes thereon and therefore, income taxes are not reflected in the financial statements.

Transportation and Exchange Imbalances

In the course of transporting natural gas and NGLs for others, the Company may receive for redelivery different quantities of natural gas or NGLs than the quantities actually redelivered. These transactions result in transportation and exchange imbalance receivables or payables that are recovered or repaid through the receipt or delivery of natural gas or NGLs in future periods, if not subject to cashout provisions. Imbalance receivables are included in accounts receivable and imbalance payables are included in accounts payable on the balance sheets and marked-to-market using current market prices in effect for the reporting period of the outstanding imbalances. Changes in market value and the settlement of any such imbalance at a price greater than or less than the recorded imbalance results in either an upward or downward adjustment, as appropriate, to the cost of natural gas sold. As of December 31, 2003 and 2004, the Company had no imbalance receivables or payables.

Segment Reporting

In accordance with SFAS No. 131, "Disclosures About Segments of an Enterprise and Related Information," the Company's reportable business segments have been identified based on the differences in the products or services provided (see Note 8).

Recent Accounting Pronouncements

SFAS No. 143, "Accounting for Asset Retirement Obligations"

In June 2001, FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations," which requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement cost is allocated to expense using a systematic and rational method and the liability is accreted to measure the change in liability due to the passage of time. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002, with early adoption permitted. The Company adopted the standard effective January 1, 2003. The primary impact of this standard relates to dismantling and site restoration of the Company's plants. Prior to SFAS 143, the Company had not recorded an obligation for these costs due to its assumption that the salvage value of the equipment would substantially offset the cost of dismantling the facilities and carrying out the necessary clean up and reclamation activities. The adoption of SFAS 143 on January 1, 2003, resulted in a net increase to Property and Equipment and Asset Retirement Obligations of approximately $293 and $366, respectively. The impact of adopting SFAS 143 has been accounted for through a cumulative effect adjustment that amounted to $73 decrease to operating activities recorded on January 1, 2003.

The following table summarizes activity related to asset retirement obligations:

	Amount
Asset Retirement Obligation, January 1, 2003	$ 366
Plus: Accretion expense	15
Asset Retirement Obligation, December 31, 2003	381
Plus: Accretion expense	15
Asset Retirement Obligation, December 31, 2004	396
Plus: Accretion expense	1
Less: Obligation transferred with net assets to affiliate	397
Asset Retirement Obligation, June 30, 2005	$

Pro forma asset retirement obligation at January 1, 2002 was $352. The effect of the change in accounting principle for the year ended December 31, 2003 was a reduction of net income of $88, including $15 accretion of the asset retirement obligation.

The following table presents the pro forma effect on net income for the years December 31, 2002 and 2003 as if SFAS 143 had been adopted prior to January 1, 2002.

	Year Ended December 31,	
	2002	2003
Net income, as reported	$ 1,514	$ 3,415
Cumulative effect adjustment		73
Asset retirement obligation accretion expense	(14)	
Asset retirement cost depreciation expense	(23)	
Net income, pro forma	$ 1,477	$ 3,488

Note 2: Property and Equipment

	As of December 31,	
	2003	2004
Pipelines and plant	$ 7,693	$ 36,249
Compressors	16,663	16,663
Other	68	130
	24,424	53,042
Less: Accumulated depreciation and amortization	2,451	4,747
	$ 21,973	$ 48,295

Depreciation and amortization charged to expense totaled $522, $1,669 and $2,296 for the years ended December 31, 2002, 2003 and 2004, respectively.

Note 3: Long-Term Debt

	As of December 31,		As of June 30,
	2003	2004	2005
Note payable bank	$ 14,166	$ 32,635	$ 33,500
Less: current maturities	3,336	9,356	33,500
Long-term portion	$ 10,830	$ 23,279	$

On December 6, 2002, Hiland executed a Credit Agreement in which a bank agreed to provide a $14.5 million senior secured credit facility. Borrowings under the credit facility are collateralized by liens on the assets of Hiland, personal guarantees of the member group and the personal guarantee of the primary stockholder of CRI. Borrowings under the credit facility bear interest, payable monthly, at a varying interest rate. Monthly repayment consists of interest plus a fixed principal payment of $200, plus an additional principal payment of 75% of EBITDA, as defined in the agreement, minus interest expense, capital expenditures and permitted tax distributions to members. The interest rate is the bank prime rate minus 25 basis points, but not less than 4.0% per annum. As of December 31, 2003, the interest rate was 4%. The credit facility matures on December 10, 2007. On April 16, 2003, Hiland executed a First Amendment to the Credit Agreement that increased the credit facility to $17.9 million and required an additional $78 fixed principal payment. On May 6, 2004, Hiland executed a Second Amendment to the Credit Agreement that increased the credit facility to $23.0 million. No other terms were changed. The credit agreement contains certain covenants. Hiland must maintain a current ratio, excluding current maturities of the credit facility, of not less than 1.0 to 1.0, and a fixed-charge ratio, tested quarterly, of not less than 1.10 to 1.0. The agreement limits Hiland's ability to assume further indebtedness, assume contingent liabilities, sell assets, make investments, cancel insurance, merge or consolidate, distribute cash to owners, change its structure or ownership, or participate in speculative trading. It also limits transactions with affiliates.

As of December 31, 2003, there was no availability on the credit facility.

Effective October 7, 2004, Hiland, with its newly formed subsidiary, Hiland Energy Partners, LLC (HEP), executed a second restated loan agreement with a bank that increased the loan to include a $17,000 revolver and an $11,000 term loan, changed the maturity date to December 2005, and modified the interest rate to prime rate. Subsequently, on November 24, 2004, Hiland, HEP, and the bank executed loan agreements to divide the loan into two separate facilities. Hiland entered into a $25,000 note with a revolving period through July 20, 2005. The note matures on February 24, 2006 and bears interest at LIBOR, which was 4.9% as of December 31, 2004. Through July 20, 2005, monthly repayment consists of accrued interest; subsequently, monthly repayment consists of accrued interest plus a principal payment equal to 70% of monthly cash flow as defined in the agreement. Borrowings are collateralized by the assets of Hiland and guarantees of certain affiliates. The agreement contains covenants among which include maintenance of an interest coverage ratio of not less than 3 to 1. On January 27, 2005, Hiland executed a First Amendment to the second restated loan agreement that increased the $25 million note an additional $5 million to $30.0 million. No other terms were changed. HEP entered into a $10,000 note that matures May 24, 2005 and bears interest at LIBOR. Monthly repayment consists of interest plus a fixed principal payment of $278 plus 75% of excess monthly cash flow, as defined in the agreement. Borrowings are collateralized by the assets of HEP and guarantees of certain affiliates. The agreement contains covenants among which include maintenance of an adjusted current ratio and a fixed charge coverage ratio within certain specifications. As of December 31, 2004, Hiland and HEP were in compliance with its financial covenants. Please see Note 10 for a description of management's intended retirement of HEP's obligation.

As of December 31, 2004, credit availability on the $25 million facility was $1.7 million. The $10 million facility had no credit availability.

During the years ended December 31, 2002, 2003 and 2004, $0, $0, and $144 of interest was capitalized into plant construction.

Future maturities of long-term debt as of December 31, 2004 are as follows:

Year Ended December 31,	Amount
2005	$ 9,356
2006	$ 23,279

Note 4: Property on Lease

On December 9, 2002 and December 20, 2002, Hiland leased compressors that it acquired at a cost of $2.1 million and $9.9 million, respectively, to CRI. The operating leases have five-year terms but are subject to cancellation by the lessee after three years. At the end of the leases, the lessee can purchase the compressors for fair market value. Otherwise, the compressors will remain the property of Hiland. On August 20, 2003, additional compressors costing $4.7 million were acquired and leased to CRI on similar terms.

On December 31, 2003 and 2004, the carrying amount (at cost) of these compressors was $16.7 million. The accumulated depreciation was $1.3 million and $2.7 million, respectively.

Schedule of minimum lease payments to the Company due for the remaining non-cancellable lease term at December 31, 2004:

Year Ended December 31,	Amount
2005	$ 3,722
2006	684
Total	$ 4,406

Please see note 9 for a discussion of Hiland's new contractual arrangement that replaces the operating leases described above.

Note 5: Commitments and Contingencies

The Company maintains a defined contribution retirement plan for its employees under which it makes discretionary contributions to the plan based on a percentage of eligible employees' compensation. During 2002, 2003 and 2004, contributions to the plan were 5.0% of eligible employees' compensation. Expense for the years ended December 31, 2002, 2003 and 2004 was approximately $21, $23 and $23, respectively.

Hiland is a party to various regulatory proceedings and may from time to time be a party to litigation which it believes will not have a materially adverse impact on Hiland's financial condition, results of operations or cash flows.

The operation of pipelines, plants and other facilities for gathering, compressing, treating, or processing natural gas, NGLs and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. Management believes that compliance with federal, state or local environmental laws and regulations will not have a material adverse effect on the Company's business, financial position or results of operations.

Note 6: Related Party Transactions

The Company purchases natural gas and NGLs from affiliated companies, principally CRI. Purchases of product totaled $0.6 million, $1.1 million, and $1.8 million for the years ended December 31, 2002, 2003 and 2004.

The Company utilizes unconsolidated affiliated companies to provide services to its plants and pipelines. The total amount paid to these companies was approximately $46, $32, and $76 during the years ended December 31, 2002, 2003 and 2004, respectively.

The Company contracts with unconsolidated affiliated companies to provide management services and certain administrative services. The total amount paid to these companies was approximately $120, $65, and $65 during the years ended December 31, 2002, 2003 and 2004, respectively.

The Company leases compressors to an affiliated company. Please see Note 4.

Note 7: Significant Customers and Suppliers

All revenues are domestic revenues and all lease revenue is from a single affiliated customer. The following table presents the top midstream customers as a percent of total revenues for the periods indicated:

	For the Year Ended December 31,		
	2002	2003	2004
Customer 1	56%	43%	
Customer 2	17%	8%	8%
Customer 3	13%	12%	14%
Customer 4	10%	3%	
Customer 5			48%

All purchases are from domestic sources. The following table presents the top midstream suppliers as a percent of total midstream purchases for the periods indicated:

	For the Year Ended December 31,		
	2002	2003	2004
Supplier 1	41%	40%	34%
Supplier 2	52%	49%	39%
Supplier 3			22%

Note 8: Business Segments

The Company's operating activities are classified into two reportable segments:

(1) Midstream, which is engaged in the gathering, compressing, dehydrating, treating and processing of natural gas and fractionating NGLs.

(2) Compression, which is engaged in providing air compression and water injection equipment for CRI's oil and gas secondary recovery operations that are ongoing in North Dakota.

The Company evaluates the performance of its segments and allocates resources to them based on operating income. The Company's operations are conducted in the United States.

Year Ended December 31, 2002, 2003 and 2004

The table below presents information about operating activities for the reportable segments for the years ended December 31, 2002, 2003, and 2004.

	Midstream	Compression	Total
Year Ended December 31, 2002			
Revenues	$ 5,480	$ 244	$ 5,724
Operating costs and expenses:			
Midstream purchases (exclusive of items shown separately below)	1,439		1,439
Operations and maintenance	1,779		1,779
Depreciation and amortization	437	85	522
Loss on asset sales	36		36
General and administrative	156		156
Total operating costs and expenses	3,847	85	3,932
Income from operations	1,633	159	1,792
Other income (expense):			
Interest and other income	27		27
Amortization of deferred loan costs	(73)		(73)
Interest expense	(214)	(18)	(232)
Total other income (expense)	(260)	(18)	(278)
Net income	$ 1,373	$ 141	$ 1,514
Total assets	$ 7,619	$ 12,159	$ 19,778
Capital expenditures	$ 528	$ 12,000	$ 12,528

	Midstream	Compression	Total
Year Ended December 31, 2003			
Revenues	$ 7,262	$ 3,300	$ 10,562
Operating costs and expenses:			
Midstream purchases (exclusive of items shown separately below)	2,826		2,826
Operations and maintenance	1,900		1,900
Depreciation and amortization	495	1,189	1,684
General and administrative	101		101
Total operating costs and expenses	5,322	1,189	6,511
Income from operations	1,940	2,111	4,051
Other income (expense):			
Interest and other income	11		11
Interest expense	(72)	(502)	(574)
Total other income (expense)	(61)	(502)	(563)
Income before cumulative change in accounting principle	1,879	1,609	3,488
Cumulative effect of change in accounting principle	(73)		(73)
Net income	$ 1,806	$ 1,609	$ 3,415
Total assets	$ 7,743	$ 15,715	$ 23,458
Capital expenditures	$ 451	$ 4,663	$ 5,114

	Midstream	Compression	Total
Year Ended December 31, 2004			
Revenues	$ 10,481	$ 3,854	$ 14,335
Operating costs and expenses:			
Midstream purchases (exclusive of items shown separately below)	4,600		4,600
Operations and maintenance	2,080		2,080
Depreciation and amortization	847	1,464	2,311
General and administrative	97		97
Total operating costs and expenses	7,624	1,464	9,088
Income from operations	2,857	2,390	5,247
Other income (expense):			
Interest and other income	1		1
Amortization of deferred loan costs	(106)		(106)
Interest expense	(144)	(517)	(661)
Total other income (expense)	(249)	(517)	(766)
Net income	$ 2,608	$ 1,873	$ 4,481
Total assets	$ 37,767	$ 13,925	$ 51,692
Capital expenditures	$ 24,781	$	$ 24,781

Note 9: Distribution of Net Assets

In connection with the formation of Hiland Partners, LP (the "Partnership") and its initial public offering on February 15, 2005, the assets and liabilities of the Company, excluding certain working capital assets and assets, liabilities, and operations relating to the Bakken gathering system, were distributed to its members and subsequently contributed by those members to the Partnership in exchange for 149 common units and 1,433 subordinated units of the Partnership. As a result of the distribution, the Company no longer has reportable segments.

Also on February 15, 2005 and in conjunction with the initial public offering, the Partnership and CRI entered into a new contractual arrangement whereby the Partnership will provide air compression and water injection services for CRI's oil and gas secondary recovery operations that are ongoing in North Dakota for a four year period with a month-to-month renewal option unless cancelled by either party. The new arrangement replaces the operating leases described in Note 4 above formerly provided by Hiland.

Note 10: Subsequent Events *(unaudited)*

Effective September 1, 2005, Hiland executed an acquisition agreement with Hiland Operating, LLC, a wholly owned subsidiary of the Partnership, pursuant to which the Partnership acquired all of the outstanding membership interests in Hiland for approximately $92.7 million in cash, $35.0 million of which was used to retire outstanding Hiland Partners, LLC indebtedness. Hiland used the proceeds from the acquisition to repay all of its outstanding indebtedness.

Report of Independent Registered Public Accounting Firm

Board of Directors
Hiland Partners GP, LLC

We have audited the accompanying balance sheet of Hiland Partners, LP as of December 31, 2004. This balance sheet is the responsibility of the Partnership's management. Our responsibility is to express an opinion on this balance sheet based on our audit.

We conducted our audit in accordance with 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 balance sheet is 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 audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's 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 balance sheet, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall balance sheet presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the balance sheet referred to above presents fairly, in all material respects, the financial position of Hiland Partners, LP as of December 31, 2004 in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 15, 2005

HILAND PARTNERS, LP
Balance Sheet
December 31, 2004

Assets		
Cash	$	1,000
Total Assets	$	1,000
Partners' Equity		
Partners' equity:		
Limited partner	$	980
General partner		20
Total partners' equity	$	1,000

See accompanying note to balance sheet.

HILAND PARTNERS, LP
Note to Balance Sheet
December 31, 2004

(1)
Organization

Hiland Partners, LP (the "Partnership"), is a Delaware limited partnership formed on October 18, 2004, to acquire all of the assets and liabilities of Continental Gas, Inc. ("CGI"), other than a portion of its working capital assets, and all of the assets and liabilities of Hiland Partners, LLC ("Hiland"), other than a portion of its working capital assets and the assets, liabilities and operations related to the Bakken gathering system. The Partnership's general partner is Hiland Partners GP, LLC. The Partnership has been formed and capitalized; however there have been no other transactions involving the Partnership prior to December 31, 2004.

On February 15, 2005, the Partnership closed its initial public offering of 2,300,000 common units (representing limited partner interests) at a price of $22.50 per unit, which included a 300,000 unit over-allotment option that was exercised by the underwriters. In addition, the Partnership issued 420,000 common units and 4,080,000 subordinated units, representing additional limited partner interests to Harold Hamm, the Harold Hamm DST Trust, the Harold Hamm HJ Trust, management and certain of their affiliates as well as a 2% general partner interest in the Partnership to Hiland Partners GP, LLC in exchange for the above described assets and liabilities of CGI and Hiland.

On February 15, 2005, the Partnership established a $55.0 million credit facility through its operating company that consists of a $47.5 million senior secured revolving credit facility to be used for funding acquisitions and other capital expenditures, issuance of letters of credit and general corporate purposes (the "revolving acquisition facility") and a $7.5 million senior secured revolving credit facility to be used for working capital and to fund distributions (the "revolving working capital facility"). The Partnership has the right to increase its borrowing capacity under the acquisition facility by an additional $35.0 million in connection with any purchase, including the Bakken gathering system.

Report of Independent Registered Public Accounting Firm

Board of Directors
Hiland Partners GP, LLC

We have audited the accompanying consolidated balance sheet of Hiland Partners GP, LLC and subsidiaries as of December 31, 2004. This balance sheet is the responsibility of the Company's management. Our responsibility is to express an opinion on this balance sheet based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the balance sheet is free of material misstatement. The Company is not required to have, nor were we engaged to perform an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company'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 balance sheet, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall balance sheet presentation. We believe that our audit of the balance sheet provides a reasonable basis for our opinion.

In our opinion, the consolidated balance sheet referred to above presents fairly, in all material respects, the financial position of Hiland Partners GP, LLC and subsidiaries as of December 31, 2004 in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
October 13, 2005

HILAND PARTNERS GP, LLC AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands)

	December 31, 2004	September 30, 2005
		(unaudited)
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2	$ 7,014
Accounts receivable:		
Trade		18,601
Affiliates		1,115
		19,716
Inventories		153
Other current assets		347
Total current assets	2	27,230
Property and equipment, net		116,239
Intangibles, net		42,281
Other assets, net		1,007
Total assets	$ 2	$ 186,757
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable	$	$ 11,774
Accounts payable-affiliates		7,656
Accrued liabilities		1,004
Total current liabilities		20,434
Long-term debt, net of current maturities		93,700
Asset retirement obligation		1,042
Minority interests	1	70,447
Commitments and contingencies		
Owners' equity	1	1,134
Total owners' equity	1	1,134
Total liabilities and owners' equity	$ 2	$ 186,757

The accompanying notes are an integral part of these consoilidated balance sheets.

HILAND PARTNERS GP, LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED BALANCE SHEETS

September 30, 2005 (unaudited) and December 31, 2004

(in thousands, except per unit information)

Note 1: Organization, Basis of Presentation, Principles of Consolidation and Significant Accounting Policies

Hiland Partners GP, LLC, (the Company") a Delaware limited liability company, was formed in October 2004 to manage the operations of Hiland Partners, LP ("the Partnership"), which received certain midstream natural gas plants, gathering systems, and compression and water injection assets previously owned by Continental Gas, Inc. ("CGI") and Hiland Partners, LLC. CGI constitutes the Partnership's predecessor. The transfer of ownership of net assets from CGI to the Partnership represented a reorganization of entities under common control and was recorded at historical cost. Accordingly, the financial statements include the historical operations of CGI prior to the transfer to the Partnership. CGI was formed in 1990 as a wholly owned subsidiary of Continental Resources, Inc. ("CRI").

CGI operated in one segment, midstream, which involved the gathering, compressing, dehydrating, treating, and processing of natural gas and fractionating natural gas liquids, or NGLs. CGI historically has owned all of our natural gas gathering, processing, treating and fractionation assets other than our Worland gathering system and our Bakken gathering system. Hiland Partners, LLC historically owned our Worland gathering system and our compression services assets, which we acquired on February 15, 2005, and our Bakken gathering system. Since the initial public offering, the Partnership has operated in midstream and compression services segments. On September 26, 2005, the Partnership acquired Hiland Partners, LLC, which at such time owned the Bakken gathering system, for $92.7 million, $35.0 million of which was used to retire outstanding Hiland Partners, LLC indebtedness.

The net assets contributed by Hiland Partners, LLC on February 15, 2005 had a fair value of $48.6 million and were contributed for 149 common units and 1,433 subordinated units.

The consolidated interim balance sheet as of September 30, 2005 included herein has been prepared without audit, pursuant to the rules and regulation of the United States Securities and Exchange Commission (the "SEC"). The consolidated unaudited balance sheet reflects all adjustments, which are in the opinion of our management, necessary for a fair presentation at September 30, 2005. Such adjustments are considered to be of a normal recurring nature.

Principles of Consolidation

Due to the Company's control of the Partnership, the consolidated balance sheet includes the accounts of the Company and the accounts of the Partnership and its subsidiaries. Unless the context otherwise requires, references to the "Company" or the "Partnership" refer to the consolidated operations of those entities. All significant intercompany transactions and balances have been eliminated.

Prior to the contribution of the assets of Continental Gas, Inc. and Hiland Partners, LLC to the Partnership on February 15, 2005, the Partnership was substantially inactive with minimal capitalization. Amounts presented in the notes to financial statements as of December 31, 2004 relate to Continental Gas, Inc., the predecessor of the Partnership, and are presented for informative purposes only.

Use of Estimates

The preparation of the consolidated balance sheets in accordance with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates.

Cash and Cash Equivalents

The Company considers all highly liquid investments with maturity of three months or less at the time of purchase to be cash equivalents.

Accounts Receivable

The majority of the accounts receivable are due from companies in the oil and gas industry as well as the utility industry. Credit is extended based on evaluation of the customer's financial condition. In certain circumstances, collateral, such as letters of credit or guarantees, is required. Accounts receivable are due within 30 days and are stated at amounts due from customers. The Company has established various procedures to manage its credit exposure, including initial credit approvals, credit limits and rights of offset. Credit losses are charged to income when accounts are deemed uncollectible, determined on a case-by-case basis when the Company believes the required payment of specific amounts owed is unlikely to occur. These losses historically have been minimal, therefore, an allowance for uncollectible accounts is not required.

Inventories

Inventories consist primarily of compressors and associated equipment. Inventories are stated at the lower of cost or estimated net realizable value.

Concentration and Credit Risk

Financial instruments that potentially subject the Company to concentrations of credit risk consist principally of cash and cash equivalents and receivables. The Company places its cash and cash equivalents with high-quality institutions and in money market funds. The Company derives its revenue from customers primarily in the natural gas and utility industries. These industry concentrations have the potential to impact the Company's overall exposure to credit risk, either positively or negatively, in that the Company's customers could be affected by similar changes in economic, industry or other conditions. However, the Company believes that the credit risk posed by this industry concentration is offset by the creditworthiness of the Company's customer base. The Company's portfolio of accounts receivable is comprised primarily of mid-size to large domestic corporate entities.

Fair Value of Financial Instruments

The Company's financial instruments, which require fair value disclosure, consist primarily of cash and cash equivalents, accounts receivable, accounts payable and bank debt. The carrying value of cash and cash equivalents, accounts receivable and accounts payable are considered to be representative of their respective fair values, due to the short maturity of these instruments. The fair value of long-term debt approximates its carrying value due to the variable interest rate feature of such debt.

Intangible and Other Assets

Intangible assets consist of the acquired value of existing contracts to sell natural gas and other NGLs and compression contracts, which do not have a significant residual value. The contracts are being amortized over ten years. Net intangible assets of $42,281 as of September 30, 2005 consist of $24,923 in gas sales contracts and $17,358 in compression contracts. The Company reviews intangible assets for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of intangible assets is not recoverable, the Company reduces the carrying amount of such assets to fair value. No impairment of intangible assets has been recorded as of September 30, 2005.

Long-Lived Assets

In accordance with Statement of Financial Accounting Standards (SFAS) No. 144, "*Accounting for the Impairment or Disposal of Long-Lived Assets*," the Company evaluates its long-lived assets of identifiable business activities for impairment when events or changes in circumstances indicate, in management's judgment, that the carrying value of such assets may not be recoverable. The determination of whether impairment has occurred is based on management's estimate of undiscounted future cash flows attributable to the assets as compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value for the assets and recording a provision for loss if the carrying value is greater than fair value. For assets identified to be disposed of in the future, the carrying value of these assets is compared to the estimated fair value less the cost to sell to determine if impairment is required. Until the assets are disposed of, an estimate of the fair value is re-determined when related events or circumstances change.

When determining whether impairment of one of the Company's long-lived assets has occurred, the Company must estimate the undiscounted cash flows attributable to the asset or asset group. The Company's estimate of cash flows is based on assumptions regarding the volume of reserves providing asset cash flow and future NGL product and natural gas prices. The amount of reserves and drilling activity are dependent in part on natural gas prices. Projections of reserves and future commodity prices are inherently subjective and contingent upon a number of variable factors, including, but not limited to:

- changes in general economic conditions in regions in which the Company's products are located;
- the availability and prices of NGL products and competing commodities;
- the availability and prices of raw natural gas supply;
- the Company's ability to negotiate favorable marketing agreements;
- the risks that third party oil and gas exploration and production activities will not occur or be successful;
- the Company's dependence on certain significant customers and producers of natural gas; and
- competition from other midstream service providers and processors, including major energy companies.

Any significant variance in any of the above assumptions or factors could materially affect the Company's cash flows, which could require the Company to record an impairment of an asset.

Derivatives

Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. SFAS No. 133 requires that an entity recognize all derivatives as either assets or liabilities in the statement of financial position and measure those instruments at fair value. SFAS No. 133 provides that normal purchases and normal sales contracts are not subject to the statement. Normal purchases and normal sales are contracts that provide for the purchase or sale of something other than a financial instrument or derivative instrument that will be delivered in quantities expected to be used or sold by the reporting entity over a reasonable period in the normal course of business. The Company's forward natural gas purchase and sales contracts are designated as normal purchases and sales. Substantially all forward contracts fall within a one-month to five-year term.

Property and Equipment

The Company's property and equipment are carried at cost. Depreciation and amortization of all equipment is determined under the straight-line method using various rates based on useful lives, 10 to 22 years for pipeline and processing plants, and 3 to 10 years for corporate and other assets. The cost of assets and related accumulated depreciation is removed from the accounts when such assets are disposed of, and any related gains or losses are reflected in current earnings. Maintenance, repairs and minor replacements are expensed as incurred. Costs of replacements constituting improvement are capitalized.

Environmental Costs

Environmental costs are expensed if they relate to an existing condition caused by past operations and do not contribute to current or future revenue generation. Liabilities are recorded when site restoration and environmental remediation and cleanup obligations are either known or considered probable and can be reasonably estimated. Recoveries of environmental costs through insurance, indemnification arrangements or other sources are included in other assets to the extent such recoveries are considered probable.

Income Taxes

The Company and the Partnership are not subject to income taxes. Accordingly, there is no provision for income taxes included in the consolidated financial statements. Taxable income, gain, loss and deductions are allocated to the owners who are responsible for payment of any income taxes thereon.

Transportation and Exchange Imbalances

In the course of transporting natural gas and NGLs for others, the Company may receive for redelivery different quantities of natural gas or NGLs than the quantities actually redelivered. These transactions result in transportation and exchange imbalance receivables or payables that are recovered or repaid through the receipt or delivery of natural gas or NGLs in future periods, if not subject to cashout provisions. Imbalance receivables are included in accounts receivable and imbalance payables are included in accounts payable on the balance sheets and marked-to-market using current market prices in effect for the reporting period of the outstanding imbalances. Changes in market value and the settlement of any such imbalance at a price greater than or less than the recorded imbalance results in either an upward or downward adjustment, as appropriate, to the cost of natural gas sold. As of December 31, 2004 and September 30, 2005 the Company had no imbalance receivables or payables.

Share-Based Compensation

The Partnership applies Accounting Principles Board Opinion No. 25 and related interpretations in accounting for its share-based compensation awards. Accordingly, no compensation cost has been recognized for unit options granted. None of the entities (the Partnership, Continental Gas, Inc., or Hiland Partners, LLC) had issued any options prior to the adoption of its incentive unit option plan on February 15, 2005.

As of September 30, 2005, there were 166 options outstanding with a weighted-average exercise price of $24.53 per unit and a weighted-average grant date fair value of $12.43 per unit. As of September 30, 2005 no options were exercisable.

SFAS No. 143, "Accounting for Asset Retirement Obligations"

In June 2001, FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations," that requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement cost is allocated to expense using a systematic and rational method and the liability is accreted to measure the change in liability due to the passage of time. The primary impact of this standard relates to dismantling and site restoration of certain of the Partnership's plants and pipelines.

Recent Accounting Pronouncements

SFAS No. 123, "Share-Based Payment"

In October 1995, the FASB issued SFAS No. 123, "Share-Based Payments," which was revised in December 2004 (collectively, "FASB 123R"). FASB 123R requires that the compensation cost relating to share-based payment transactions be recognized in financial statements and that cost will be measured based on the fair value of the equity or liability instruments issued. The effect of the standard will be to require entities to measure the cost of employee services received in exchange for stock or unit options based on the grant-date fair value of the award, and to recognize the cost over the period the employee is required to provide services for the award. The Company will be required to apply SFAS 123R as of the beginning of its first annual reporting period on or after July 1, 2005. Early adoption is permitted. The Company expects to apply the Statement beginning January 1, 2006 using the modified prospective method.

Note 2: Property and Equipment

Property and equipment at September 30, 2005 consists of the following:

Land	$ 225
Pipelines and plants	119,168
Compression and water injection equipment	19,213
Other	3,346
	141,952
Less: accumulated depreciation and amortization	25,713
	$ 116,239

Note 3: Credit Facility

Concurrently with the closing of the Partnership's initial public offering, it entered into a three-year $55.0 million senior secured revolving credit facility. MidFirst Bank, a federally chartered savings association located in Oklahoma City, Oklahoma, is a lender and serves as administrative agent under this facility. The credit facility consists of a $47.5 million senior secured revolving credit facility to be used for funding acquisitions and other capital expenditures, issuance of letters of credit, and general corporate purposes (the "revolving acquisition facility") and a $7.5 million senior secured revolving credit facility to be used for working capital and to fund distributions (the "revolving working capital facility").

On September 26, 2005, concurrently with the acquisition of Hiland Partners, LLC, the Partnership amended its senior secured revolving credit facility to increase its borrowing capacity under the facility from $55.0 million to $125.0 million, consistiong of a $117.5 million acquisition facility and a $7.5 million working capital facility. On September 26, 2005, the Partnership incurred $93.7 million of indebtedness under the credit facility in connection with its acquisition of Hiland Partners, LLC. The credit facility will mature in February 2008. At that time, the agreement will terminate and all outstanding amounts thereunder will be due and payable.

The Partnership's obligations under the credit facility are secured by substantially all of its assets and guaranteed by the Partnership and its subsidiaries, other than Hiland Operating, LLC, which is the borrower under the credit facility. The credit facility is non-recourse to the Company.

Indebtedness under the credit facility will bear interest, at the Partnership's option, at either (i) an Alternate Base Rate plus an applicable margin ranging from 50 to 175 basis points per annum or (ii) LIBOR plus an applicable margin ranging from 150 to 275 basis points per annum based on our ratio of total debt to EBITDA. The Alternate Base Rate is a rate per annum equal to the greatest of (a) the Prime Rate in effect on such day, (b) the base CD rate in effect on such day plus 1.50% and (c) the Federal Funds effective rate in effect on such day plus $^1/_2$ of 1%. A letter of credit fee will be payable for the aggregate amount of letters of credit issued under the credit facility at a percentage per annum equal to 1.0%. An unused commitment fee ranging from 30 to 50 basis points per annum based on our ratio of total debt to EBITDA will be payable on the unused portion of the credit facility.

The credit facility imposes certain requirements, including: prohibition against distribution to unitholders if, before or after the distribution, a potential default or an event of default as defined in the agreement would occur; limitations on the Partnership's ability to incur debt, grant liens, make loans, acquisitions, and investments, change the nature of the Partnership's business, enter a merger or consolidation, or sell assets, amend material agreements; and covenants that require maintenance of certain levels of tangible net worth, EBITDA to interest expense ratio, and debt to EBITDA ratio. If an event of default exists under the agreement, the lenders will be able to accelerate the maturity of the debt and exercise other rights and remedies. As of September 30, 2005, the Partnership was in compliance with all of the covenants associated with the credit facility.

Note 4: Commitments and Contingencies

The Partnership has executed fixed price physical forward sales contracts on approximately 50,000 MMBtu per month through December 2007 with weighted average fixed prices per MMBtu of $4.53, $4.47 and $4.49, respectively, for years 2005 through 2007. The Partnership also has fixed price physical forward sales contracts to sell approximately 50,000 MMBtu of natural gas per month from October 2005 through December 2006 with weighted average fixed prices per MMBtu of $9.52. Such contracts qualify as normal sales under SFAS No. 133 and are therefore not marked to market as derivatives.

The Company maintains a defined contribution retirement plan for its employees under which it makes discretionary contributions to the plan based on a percentage of eligible employees' compensation.

The Company and other affiliated companies participate jointly in a self-insurance pool (the "Pool") covering health and workers' compensation claims made by employees up to the first $150 and $500, respectively, per claim. Any amounts paid above these are reinsured through third party providers. Premiums charged to the Partnership are based on estimated costs per employee of the Pool. No additional premium assessments are anticipated for periods prior to September 30, 2005. Property and general liability insurance is maintained through third-party providers with a $100 deductible on each policy.

The Partnership is a party to various regulatory proceedings and various other litigation that it believes will not have a materially adverse impact on the Partnership's financial condition, results of operations or cash flows.

The operation of pipelines, plants and other facilities for gathering, compressing, treating, or processing natural gas, NGLs and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. Management believes that compliance with federal, state or local environmental laws and regulations will not have a material adverse effect on the Company's business, financial position or results of operations.

Note 5: Major Customers

At December 31, 2004 and as of September 30, 2005, the Partnership had trade receivables due from one customer that represented approximately 38.4% and 36.9%, respectively, of the Partnership's total net accounts receivable. Management attempts to mitigate its credit risk by establishing strict credit policies for significant accounts receivable.

Note 6: Lease Commitments

The Partnership leases certain facilities, pipelines and equipment under operating leases, most of which contain annual renewal options. At December 31, 2004, the minimum future rental commitments under operating leases having non-cancelable lease terms in excess of one year, including leases from related parties, total:

Year	Amount
2005	$ 86
2006	92
2007	93
2008	92
2009	61
Thereafter	13
Total	$ 437

Note 7: Partner's capital

The Partnership Agreement of Hiland Partners, LP requires that the Partnership distribute all of its cash on hand at the end of each quarter, less reserves established at the Company's discretion. The Company refers to this as "available cash." The amount of available cash may be greater than or less than the minimum quarterly distributions. In general, the Partnership will pay any cash distribution made each quarter in the following manner:

- first, 98% to the common units and 2% to the Company as general partner, until each common unit has received a minimum quarterly distribution of $0.45 plus any arrearages from prior quarters

- second, 98% to the subordinated units and 2% to the Company as general partner, until each subordinated unit has received a minimum quarterly distribution of $0.45 and;

- third, 98% to all units pro rata, and 2% to the Company as general partner, until each unit has received a distribution of $0.495

If cash distributions per unit exceed $0.495 in any quarter, the Company as general partner will receive increasing percentages, up to a maximum of 50% of the cash distributed in excess of that amount. The Company refers to these distributions as "incentive distributions."

The distributions on the subordinated units may be reduced or eliminated if necessary to ensure the common units receive their minimum quarterly distribution. Subordinated units will not accrue arrearages. The subordination period will end once the Partnership meets certain financial tests, but not before March 31, 2010. These financial tests require the Partnership to have earned and paid the minimum quarterly distribution on all of their outstanding units for three consecutive four-quarter periods. When the subordination period ends, all remaining subordinated units will convert into common units on a one-for-one basis, and the common units will no longer be entitled to arrearages.

The Company has the right but not the obligation to maintain net general partner capital equal to 2% of Partnership capital.

On April 25, 2005, the Partnership announced its first regular cash distribution in 2005 of $0.225 per unit, based on the minimum quarterly cash distribution of $0.45 prorated for the period since the initial public offering on February 15, 2005. The distribution to all common, subordinated and general partner units was paid May 13, 2005, to all unitholders of record on May 5, 2005. The aggregate amount of the distribution was $1.6 million.

On July 26, 2005, the Partnership announced a regular cash distribution of $0.4625 per unit for the second quarter of 2005. This represents an increase of $0.0125 per unit over the minimum quarterly distribution rate of $0.45. The distribution to all common, subordinated and general partner units is to be paid on August 12, 2005 to all unitholders of record on August 5, 2005. The aggregate amount of the distribution was $3.2 million.

Note 8: Restricted Units

During the quarter, the Partnership issued 8,000 restricted common units to our non-employee board members. The Partnership has recorded $324 as unearned compensation in owners' equity based on the fair market value of the units on the date of grant. The restricted units vest over a four year period from the date of issuance. Periodic distributions on the restricted units will be held in trust by us until the units vest. As a result of the additional restricted common units issued, we contributed $6 to the Partnership to maintain our 2% ownership. Our equivalent general partner units increased accordingly.

Note 9: Related Party Transactions

The Partnership purchases natural gas and NGLs from affiliated companies, leases office space under operating leases from affiliates, and utilizes affiliated companies to provide services to its plants and pipelines and certain administrative costs. Such transactions result in accounts receivable from or accounts payable to affiliates.

Accounts receivable affiliates of $758 at December 31, 2004 includes $682 from one affiliate for midstream sales. Accounts receivable affiliates of $1,115 at September 30, 2005 includes $1,102 from the same affiliate for midstream sales.

Accounts payable affiliates of $2,998 at December 31, 2004 is all payable to one affiliate for midstream purchases. Accounts payable affiliates of $7,656 at September 30, 2005 includes $5,258 due to the same affiliate for midstream purchases. Accounts payable to affiliate at September 30, 2005 also includes $2,119 payable to the prior owners of Hiland Partners, LLC as final settlement for the Bakken Acquisition.

Note 10: Unconsolidated Parent Company Balance Sheet

Presented below is the Company's unconsolidated balance sheet as of:

	December 31, 2004	September 30, 2005
	(in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1	$ 198
Accounts receivable affiliates		95
Total current assets	1	293
Investment in Hiland Partners, LP		1,040
Total assets	$ 1	$ 1,333
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable	$	$ 55
Accounts payable affiliates		83
Accrued liabilities		61
Total current liabilities		199
Owners' equity	1	1,134
Total liabilities and owners' equity	$ 1	$ 1,333

Note 11: Subsequent Event (unaudited)

On October 25, 2005, the Partnership announced a regular cash distribution of $0.5125 per unit for the third quarter of 2005. This represents an increase of $0.0625 per unit over the Partnership's minimum quarterly distribution rate of $0.45 and an increase of $.05 per unit over its distribution made on August 12, 2005. The distribution to all common, subordinated and general partner units is to be paid on November 14, 2005 to all unitholders of record on November 4, 2005. The aggregate amount of the distribution will be $3.5 million. As provided for in the Partnership Agreement, the Company is entitled to receive increasing percentages, up to a maximum of 50% of the cash distributed in excess of $0.495 in any quarter as "incentive distributions." This distribution of $0.5125 per unit exceeds the $0.495 per unit by $0.0175. Accordingly, the Company will receive an additional 15% of the excess, or $21.

In October 2005, the Partnership executed swap contracts relating to a portion of its residue gas sales from the Bakken gathering system for the fixed prices noted below. Under these swap contracts, the Partnership will either pay or receive the difference between the fixed prices below and the Colorado Interstate Gas (CIG) index price. As a result, the Partnership has hedged a portion of its expected exposure to natural gas prices in 2006 and 2007 at the Bakken gathering system. The following table provides information about the Partnership's financial derivative instruments:

Natural Gas Swaps	**Monthly Volume (MMBtu)**	**Price ($/MMBtu)**
May 2006-December 2006	40,000	$ 8.78
January 2007-October 2007	40,000	$ 7.83

The Partnership intends to offer additional common units, representing limited partner interests, pursuant to a public offering. The Partnership intends to use the proceeds from such offering to repay outstanding indebtedness incurred to fund the acquisition of Hiland Partners, LLC.

On November 8, 2005, the Partnership entered into a new 15-year definitive gas purchase agreement with Continental Resources, Inc. under which it will gather, treat and process additional natural gas, which is produced as a by-product of Continental Resources' secondary oil recovery operations, in the areas specified by the contract. In return, the Partnership will receive 50% of the proceeds attributable to residue gas and natural gas liquids as well as certain fixed fees associated with gathering and treating the natural gas. In order to fulfill its obligations under the agreement, the Partnership intends to expand its Badlands gas gathering system and processing plant located in Bowman County, North Dakota. This expansion project will include the construction of a 40,000 Mcf/d nitrogen rejection plant and the expansion of our existing Badlands field gathering infrastructure. The expansion project, which is targeted for completion in the fourth quarter of 2006, is expected to cost approximately $40.0 million, which the Partnership intends to fund using its existing bank credit facility.

APPENDIX A

GLOSSARY OF TERMS

adjusted operating surplus: For any period, operating surplus generated during that period is adjusted to:

(a) decrease operating surplus by:

(1) any net increase in working capital borrowings during that period; and

(2) any net reduction in cash reserves for operating expenditures during that period not relating to an operating expenditure made during that period; and

(b) increase operating surplus by:

(1) any net decrease in working capital borrowings during that period; and

(2) any net increase in cash reserves for operating expenditures during that period required by any debt instrument for the repayment of principal, interest or premium.

Adjusted operating surplus does not include that portion of operating surplus included in clause (a) (1) of the definition of operating surplus.

available cash: For any quarter ending prior to liquidation:

(a) the sum of:

(1) all cash and cash equivalents of Hiland Partners, LP and its subsidiaries on hand at the end of that quarter; and

(2) all additional cash and cash equivalents of Hiland Partners, LP and its subsidiaries on hand on the date of determination of available cash for that quarter resulting from working capital borrowings made after the end of that quarter;

(b) less the amount of cash reserves established by our general partner to:

(1) provide for the proper conduct of the business of Hiland Partners, LP and its subsidiaries (including reserves for future capital expenditures and for future credit needs of Hiland Partners, LP and its subsidiaries) after that quarter;

(2) comply with applicable law or any debt instrument or other agreement or obligation to which Hiland Partners, LP or any of its subsidiaries is a party or its assets are subject; and

(3) provide funds for minimum quarterly distributions and cumulative common unit arrearages for any one or more of the next four quarters;

provided, *however*, that our general partner may not establish cash reserves pursuant to clause (b)(3) immediately above if the effect of such reserves would prevent us from distributing the minimum quarterly distribution on all common units and any cumulative common unit arrearages thereon for that quarter; and

provided, *further*, that disbursements made by us or any of our subsidiaries or cash reserves established, increased or reduced after the end of that quarter but on or before the date of determination of available cash for that quarter shall be deemed to have been made, established, increased or reduced, for purposes of determining available cash, within that quarter if our general partner so determines.

Bbls: Barrels.

Btu: British Thermal Units.

capital account: The capital account maintained for a partner under the partnership agreement. The capital account of a partner for a common unit, a subordinated unit, an incentive distribution right or any other partnership interest will be the amount which that capital account would be if that common unit, subordinated unit, incentive distribution right or other partnership interest were the only interest in Hiland Partners, LP held by a partner.

capital surplus: All available cash distributed by us from any source will be treated as distributed from operating surplus until the sum of all available cash distributed since the closing of the initial public offering equals the operating surplus as of the end of the quarter before that distribution. Any excess available cash will be deemed to be capital surplus.

closing price: The last sale price on a day, regular way, or in case no sale takes place on that day, the average of the closing bid and asked prices on that day, regular way, in either case, as reported in the principal consolidated transaction reporting system for securities listed or admitted to trading on the principal national securities exchange on which the units of that class are listed or admitted to trading. If the units of that class are not listed or admitted to trading on any national securities exchange, the last quoted price on that day. If no quoted price exists, the average of the high bid and low asked prices on that day in the over-the-counter market, as reported by the NASDAQ National Market or any other system then in use. If on any day the units of that class are not quoted by any organization of that type, the average of the closing bid and asked prices on that day as furnished by a professional market maker making a market in the units of the class selected by the our board of directors. If on that day no market maker is making a market in the units of that class, the fair value of the units on that day as determined reasonably and in good faith by our board of directors.

common unit arrearage: The amount by which the minimum quarterly distribution for a quarter during the subordination period exceeds the distribution of available cash from operating surplus actually made for that quarter on a common unit, cumulative for that quarter and all prior quarters during the subordination period.

current market price: For any class of units listed or admitted to trading on any national securities exchange as of any date, the average of the daily closing prices for the 20 consecutive trading days immediately prior to that date.

interim capital transactions: The following transactions if they occur prior to liquidation:

(a) borrowings, refinancings or refundings of indebtedness and sales of debt securities (other than for working capital borrowings and other than for items purchased on open account in the ordinary course of business) by Hiland Partners, LP or any of its subsidiaries;

(b) sales of equity interests by Hiland Partners, LP or any of its subsidiaries; and

(c) sales or other voluntary or involuntary dispositions of any assets of Hiland Partners, LP or any of its subsidiaries (other than sales or other dispositions of inventory, accounts receivable and other assets in the ordinary course of business, and sales or other dispositions of assets as a part of normal retirements or replacements).

MMBbls: One million barrels.

MMBtu: One million British Thermal Units.

MMcf: One million cubic feet of natural gas.

MBbls/d: One thousand barrels per day.

MMBtu/d: One million British Thermal Units per day.

MMcf/d: One million cubic feet per day.

NGLs: Natural gas liquids which consist primarily of ethane, propane, isobutane, normal butane and natural gas.

operating expenditures: All of our expenditures and expenditures of our subsidiaries, including, but not limited to, taxes, reimbursements of our general partner, repayment of working capital borrowings, debt service payments and capital expenditures, subject to the following:

(a) Payments (including prepayments) of principal of and premium on indebtedness, other than working capital borrowings will not constitute operating expenditures.

(b) Operating expenditures will not include:

(1) capital expenditures made for acquisitions or for capital improvements;

(2) payment of transaction expenses relating to interim capital transactions; or

(3) distributions to unitholders.

operating surplus: For any period prior to liquidation, on a cumulative basis and without duplication:

(a) the sum of:

(1) $7.7 million plus all the cash of Hiland Partners, LP and its subsidiaries on hand as of the closing date of our initial public offering;

(2) all cash receipts of Hiland Partners, LP and our subsidiaries for the period beginning on the closing date of our initial public offering and ending with the last day of that period, other than cash receipts from interim capital transactions; and

(3) all cash receipts of Hiland Partners, LP and our subsidiaries after the end of that period but on or before the date of determination of operating surplus for the period resulting from working capital borrowings; less

(b) the sum of:

(1) operating expenditures for the period beginning on the closing date of our initial public offering and ending with the last day of that period; and

(2) the amount of cash reserves that is established by our general partner to provide funds for future operating expenditures; provided however, that disbursements made (including contributions to a partner of Hiland Partners, LP and our subsidiaries or disbursements on behalf of a partner of Hiland Partners, LP and our subsidiaries) or cash reserves established, increased or reduced after the end of that period but on or before the date of determination of available cash for that period shall be deemed to have been made, established, increased or reduced for purposes of determining operating surplus, within that period if our general partner so determines.

residue gas: The pipeline quality natural gas remaining after natural gas is processed.

subordination period: The subordination period will extend from the closing of the initial public offering until the first day of any quarter beginning after March 31, 2010 for which:

(a) distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equaled or exceeded the sum of the minimum quarterly distributions on all of the outstanding common units and subordinated units for each of the twelve consecutive quarters immediately preceding that date;

(b) the adjusted operating surplus generated during each of the three consecutive, non-overlapping four quarter periods, immediately preceding that date equaled or exceeded the sum of the minimum quarterly distributions on all of the common units and subordinated units that were outstanding during those periods on a fully diluted basis; and

(c) there are no outstanding cumulative common units arrearages.

throughput: The volume of natural gas transported or passing through a pipeline, plant, terminal or other facility.

working capital borrowings: Borrowings exclusively for working capital purposes made pursuant to a credit facility or other arrangement to the extent such borrowings are required to be reduced to a relatively small amount each year for an economically meaningful period of time.

You may rely on the information contained in this prospectus. We have not authorized anyone to provide information different from that contained in this prospectus. Neither the delivery of this prospectus nor sale of common units means that information contained in this prospectus is correct after the date of this prospectus. This prospectus is not an offer to sell or solicitation of an offer to buy these common units in any circumstances under which the offer or solicitation is unlawful.

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