Hiland Partners, LP
Form 10-K
March 16, 2007

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2006

Commission file number: 000-51120

Hiland Partners, LP

(Exact name of Registrant as specified in its charter)

DELAWARE	**71-0972724**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
205 West Maple, Suite 1100	
Enid, Oklahoma	**73701**
(Address of principal executive offices)	(Zip code)

Registrant s telephone number including area code **(580) 242-6040**

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

Common limited partner units

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

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of Securities Act. Yes o No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of Act. Yes o No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this

Form 10-K or any amendment to this Form 10-K. x

Indicate by check whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

Large accelerated filer o   Accelerated filer x   Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes o No x

The aggregate market value of common limited partner units held by non-affiliates of the registrant was approximately $182 million on June 30, 2006 based on the last sales price as quoted on the Nasdaq National Market.

At March 5, 2007, there were 5,206,343 common units and 4,080,000 subordinated units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: **None**

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PART I

Items 1. and 2.   Business and Properties

Our Formation, Acquisitions and Public Offerings

Hiland Partners, LP is a Delaware limited partnership formed in October 2004 to own and operate the assets that had historically been owned and operated by Continental Gas, Inc. (CGI) and Hiland Partners, LLC.

CGI historically owned all of our natural gas gathering, processing, treating and fractionation assets other than our Worland and Bakken gathering systems and certain systems acquired or constructed since our formation. Prior to July 21, 2004, CGI was owned by Continental Resources, Inc. (CRI), an independent exploration and production company owned by Harold Hamm, the Chairman of the Board of Directors of our general partner and the Harold Hamm DST and the Harold Hamm HJ Trusts, which are trusts established for the benefit of Harold Hamm s children and which we refer to herein as the Hamm Trusts. On July 21, 2004, CRI completed the transfer of CGI to Harold Hamm and the Hamm Trusts. Hiland Partners, LLC historically owned our Worland gathering system, our compression services assets and the Bakken gathering system.

In connection with our initial public offering, the former owners of CGI and Hiland Partners, LLC and certain of our affiliates, including our general partner, contributed to us all of the assets and operations of CGI, 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.

Effective September 1, 2005, we purchased the outstanding membership interests in Hiland Partners, LLC, the principal asset of which was the Bakken gathering system, for $92.7 million. We initially financed the acquisition from borrowings on our amended credit facility. On November 21, 2005, we completed our second public offering, whereby we issued 1,630,000 common units at an offering price of $41.77 per common unit. Proceeds totaled $66.1 million, net of the underwriter discount of $3.4 million. Offering costs incurred amounted to $0.6 million. We used $65.2 million of the net proceeds to repay a portion of credit facility borrowings we had used to acquire Hiland Partners, LLC.

On May 1, 2006, we acquired the Kinta Area gathering assets from Enogex Gas Gathering, L.L.C., consisting of certain eastern Oklahoma gas gathering assets, for $96.4 million. We financed this acquisition with $61.2 million of borrowings from our credit facility and $35.0 million of proceeds from the issuance to Hiland Partners GP, LLC, our general partner, of 761,714 common units and 15,545 general partner equivalent units, both at $45.03 per unit.

On September 25, 2006, certain affiliated unitholders contributed (i) all of the membership interests in our general partner, which owns the 2% general partner interest and all of the incentive distribution rights in us and (ii) 1,301,471 common units (including 761,714 common units held by our general partner) and 4,080,000 subordinated units in us to Hiland Holdings GP, LP, a publicly owned limited partnership (NASDAQ: HPGP), in exchange for 13,550,000 limited partner units, representing a 62.7% ownership in Hiland Holdings GP, LP. Hiland Partners GP Holdings, LLC, a Delaware limited liability company formed on May 10, 2006, is the general partner of Hiland Holdings GP, LP.

References in this annual report on Form 10-K to Hiland Partners, we, our, us or similar terms refer to Hiland Partners, LP and its operating subsidiaries after giving effect to the formation transactions described above. References to Hiland Holdings refer to Hiland Holdings GP, 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 CRI 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 CRI, an exploration and production company wholly owned by affiliates of our general partner. CRI 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 13 natural gas gathering systems with approximately 1,844 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 CGI, then a subsidiary of CRI, 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 CRI has active exploration and production assets and through acquisitions of existing systems, which we have then expanded. Since inception, we have constructed 395 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 acquired from an affiliate of our general partner, which currently consists of 334 miles of gas gathering pipeline, a natural gas processing plant, two compressor stations and one fractionation facility. We have also acquired 1,115 miles of natural gas gathering pipelines, one natural gas processing plant, one treating facility and one fractionation facility. Our total segment margin for the years ended December 31, 2006 and 2005 was $63.5 million and $33.5 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

Resignation of Randy Moeder. On March 14, 2007, we announced that Randy Moeder intends to resign as Chief Executive Officer and director of both our general partner and the general partner of Hiland Holdings GP, LP to pursue other career opportunities. Mr. Moeder has agreed to remain in such positions for approximately six months. Harold Hamm, Chairman of the board of directors of our general partner, is heading up a committee to secure a replacement for Mr. Moeder.

Registration Statement. On January 23, 2007 we, along with Hiland Partners Finance Corp., our wholly owned subsidiary, filed an S-3/A registration statement with the Securities and Exchange Commission to register common unit and debt securities with a maximum aggregate offering price of $500.0 million. The securities we may offer include common units representing limited partnership interests in us, and debt securities, which may be either senior debt securities or subordinated debt securities.

Woodford Shale Project. On December 12, 2006 we entered into an agreement to construct and operate gathering pipelines and related facilities associated with the development of a portion of the acreage owned by CRI in the Woodford shale reserve in the Arkoma Basin of southeastern Oklahoma. We plan to make an initial capital investment of approximately $13.0 million by the end of 2007 and to invest an additional $10.0 million over the subsequent four years to build a 40,000 Mcf/d refrigeration processing plant and install field gathering, compression and associated equipment. The new gathering system will be designed to provide low-pressure and highly reliable gathering, compression and processing services. The gathering infrastructure is expected to include more than 15,500 horsepower of compression to provide takeaway capacity in excess of 40,000 Mcf/d. The agreement grants us the right to process the gas and further provides that we will receive certain fixed fees for the dehydration, gathering and compression of the gas for an initial term of 10 years. Expected startup of the initial phase of the project should occur during the second quarter of 2007.

Acquisition of Kinta Area Gathering Assets. On May 1, 2006, we acquired certain Kinta Area gathering assets from Enogex Gas Gathering, L.L.C. for $96.4 million, including certain closing costs. The acquisition was primarily financed with $61.2 million in borrowings under our credit facility and the sale for $35.0 million of common units and general partner units to our general partner, as described below. The acquired assets, which are located in the eastern Oklahoma Arkoma Basin, have approximately 689 wellhead receipt points and include five separate low pressure natural gas gathering systems consisting of 573 miles of natural gas gathering pipelines that were gathering approximately 134,000 Mcf/d as of December 31, 2006 and 27 compressor units capable of over 40,500 horsepower of compression. The natural gas gathering systems operate under contracts with producers that provide for services under fixed-fee arrangements.

Equity Financing. To partially finance the acquisition of the Kinta Area gathering assets, on May 1, 2006, we sold 761,714 common units and 15,545 general partner units to our general partner for $45.03 per unit, or $35.0 million in the aggregate. The purchase price was equal to the average closing price of our common units for the three trading days immediately preceding May 1, 2006. Our general partner s board of directors, as well as the conflicts committee of the board of directors, consisting of two independent directors, approved the transaction.

Badlands Expansion Project. On November 8, 2005, we entered into a new 15-year definitive gas purchase agreement with CRI under which we will gather, treat and process additional natural gas, which is produced as a by-product of CRI s 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 a fixed fee of $0.20 per Mcf for gathering and treating the natural gas, plus an additional $0.60 per Mcf fee for the first 36 Bcf of natural gas gathered. Our general partner s board of directors, as well as the conflicts committee of the board, has approved the agreement.

In order to fulfill our obligations under the agreement, we are in the process of expanding 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, which is expected to be operational in the second quarter of 2007, and the expansion of our existing Badlands field-gathering infrastructure. We intend to invest approximately $40.0 million in the expansion project by the second quarter of 2007, of which approximately $31.7 million had been invested as of December 31, 2006. We expect to invest an additional $9.5 million in 2007 on this project to expand the system.

On February 1, 2006, we entered into a five-year definitive purchase agreement with a producer to build additional compression facilities and to expand our existing Badlands gas gathering system into South Dakota. The gathering project was completed in the fourth quarter of 2006 at a cost of $3.1 million, which was funded from borrowings on our bank credit facility.

Other Expansion Projects. During the fourth quarter of 2006, we completed the construction a 25,000 Mcf/d natural gas processing facility along our existing Matli gas gathering system. This new facility now processes the existing gas supply and provides additional plant processing capacity for increased system volumes. The $3.1 million investment in this expansion project was also funded from borrowings on our bank credit facility.

In the fourth quarter of 2006, we completed the installation of additional gathering and compression infrastructure at our Bakken gathering system to increase the system s capacity from approximately 20,000 Mcf/d to 25,000 Mcf/d and are currently in the process of expanding the existing NGL fractionation facilities at the processing plant to fractionate increased NGL volumes from both the Bakken processing plant and the Badlands processing plant.

In the first quarter of 2007 we completed the installation of additional pipelines and compression facilities at our Eagle Chief gathering system and increased our system capacity from approximately 30,000 Mcf/d to approximately 35,500 Mcf/d due to increased volumes on this system.

We are in the process of installing four amine-treating facilities at several of our Kinta Area gathering system locations to remove excess carbon dioxide levels from the natural gas. We are also installing additional compression facilities to expand the current capacity by approximately 3,000 Mcf/d on these gathering systems. We will invest approximately $6.0 million on these projects and expect that the treating facilities will be completed by the end of the first quarter of 2007 and the compression facilities will be completed by the end of the third quarter of 2007.

Refinancing of Our Credit Facility. On June 8, 2006, we amended our existing $125 million senior credit facility to, among other things, increase our borrowing base to $200 million and revise certain covenants. For a more complete discussion of our credit facility, please see Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Credit Facility.

Board Member Selections. On August 11, 2006, we announced that the board of directors of our general partner had appointed Mr. John T. McNabb, II and Dr. David L. Boren as directors. Mr. McNabb and Dr. Boren were named to the conflicts committee of the board of directors, with Mr. McNabb named to chair the committee. 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.

Distribution Increase. On January 25, 2007 we declared a cash distribution for the fourth quarter of 2006. The declared quarterly distributions on our common and subordinated units increased to $0.7125 per unit (an annualized rate of $2.85 per unit) from $0.70 per unit (an annualized rate of $2.80 per unit). This represents a 1.8% increase over the prior quarter and a 14.0% increase over the distribution for the same quarter of the prior year. The distribution was paid on February 14, 2007 to unitholders of record on February 5, 2007. 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, 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 and 50% of the excess over $0.675 per unit per quarter.

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 575-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 five compressor stations with approximately 12,400 horsepower on the system. 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 35,500 Mcf/d and average throughput was approximately 25,331 Mcf/d for the year ended December 31, 2006. The system represented approximately 20.1% of our total segment margin for the year ended December 31, 2006.

- Bakken Gathering System. The Bakken gathering system is a 334-mile gas gathering system located in Richland County, Montana that gathers, compresses, dehydrates and processes natural gas, and fractionates NGLs. This system includes the Bakken processing plant, three compressor stations and one fractionation facility. The total system has approximately 10,600 horsepower installed. 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 17,290 Mcf/d for the year ended December 31, 2006. The system represented approximately 34.3% of our total segment margin for the year ended December 31, 2006.

- 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, six compressor stations, one treating facility and one fractionation facility, with a total installed horsepower of nearly 5,500. The Worland gathering system and the Worland processing plant were contributed to us on February 15, 2005 in connection with our formation and our initial public offering. Our Worland gathering system has a capacity of 8,000 Mcf/d and average throughput was approximately 2,759 Mcf/d for the year ended December 31, 2006. The system represented approximately 6.9% of our total segment margin for the year ended December 31, 2006.

- Badlands Gathering System. The Badlands gathering system is a 141-mile gas gathering system with about 5,900 horsepower located in southwest North Dakota that gathers, compresses, dehydrates, treats and processes natural gas, and fractionates NGLs. The system includes the Badlands processing plant, five 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 2,489 Mcf/d for the year ended December 31, 2006. The system represented approximately 8.8% of our total segment margin for the year ended December 31, 2006.

- Matli Gathering System. The Matli gathering system is a 52-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 which combined have approximately 6,950 horsepower. We constructed the Matli gathering system in 1999 and in December 2006 we completed the construction of a new processing plant. Our Matli gathering system has a capacity of 25,000 Mcf/d and average throughput was approximately

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15,231 Mcf/d for the year ended December 31, 2006. The system represented approximately 5.0% of our total segment margin for the year ended December 31, 2006.

- Kinta Area Gathering Systems. The Kinta Area gathering systems we acquired on May 1, 2006 include five separate low pressure natural gas gathering systems located in the eastern Oklahoma Arkoma Basin covering 573 miles of natural gas gathering pipelines. The systems include twelve compressor stations, which are comprised of 27 units with an aggregate of approximately 40,500 horsepower. Our Kinta Area gathering systems have an aggregate capacity of 180,000 Mcf/d and average throughput was approximately 134,140 Mcf/d from May 1, 2006 to December 31, 2006. The systems represented approximately 16.4% of our total segment margin for the year ended December 31, 2006.

- Other Systems. We also own three natural gas gathering systems located in Texas, Mississippi and Oklahoma. These systems represented approximately 0.9% of our total segment margin for the year ended December 31, 2006.

The following table contains certain information regarding our gathering systems as of or for the year ended December 31, 2006.

Asset	**Type**	**Length (Miles)**	**Wells Connected**	**Throughput Capacity(1)**	**Average Throughput(1)**	**Utilization of Capacity**	**Percent of Total Segment Margin**
Eagle Chief gathering system	Gathering pipelines	575	423	30,000	25,331	84.4 %	
	Processing plant			35,000	25,331	72.4 %	20.1 %
Bakken gathering system	Gathering pipelines	334	224	25,000	17,290	69.2 %	
	Processing plant			25,000	17,290	69.2 %	
	Fractionation facility (Bbls/d)			4,600	2,646	57.5 %	34.3 %
Worland gathering system	Gathering pipelines	151	94	8,000	2,759	34.5 %	
	Processing plant			8,000	2,759	34.5 %	
	Treating facility			8,000	2,759	34.5 %	
	Fractionation facility (Bbls/d)			650	299	46.0 %	6.9 %
Badlands gathering system	Gathering pipelines	141	106	5,000	2,489	49.8 %	
	Processing plant			5,000	2,489	49.8 %	
	Treating facility			7,100	2,489	35.1 %	
	Fractionation facility (Bbls/d)			600	312	52.0 %	8.8 %
Matli gathering system	Gathering pipelines	52	48	25,000	15,231	60.9 %	
	Processing plant			25,000	8,986	35.9 %	
	Treating facility			20,000	8,686	43.4 %	5.0 %
Kinta Area gathering systems(2)	Gathering pipelines	573	689	180,000	134,140	74.5 %	16.4 %
Other Systems	Gathering pipelines	18	33	7,000	2,531	36.2 %	0.9 %
	Total	1,844	1,617				92.4 %

(1) Throughput capacity and average throughput are measured in Mcf/d for the gathering pipelines, processing plants and treating facilities and in Bbls/d for the fractionation facilities shown on this chart.

(2) The Kinta Area gathering systems were acquired on May 1, 2006. As such, the systems average throughput is computed from the effective date to December 31, 2006.

Compression Segment

We provide air and water compression services to CRI 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 CRI and are ultimately utilized by CRI in its oil and gas secondary operations. The natural gas produced by CRI flows through our Badlands gathering system. Our compression segment represented approximately 7.6% of our total segment margin for the year ended December 31, 2006.

Financial Information About Segments

See Part II, Item 8 Financial Statements and Supplementary Data.

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, we have 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 nine 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 198 miles of gathering pipeline and acquiring approximately 377 miles of gathering pipeline in five separate transactions. We have also utilized acquisitions such as our purchases of the 569-mile Kinta Area gathering assets located in eastern Oklahoma on May 1, 2006 and the 151-mile Worland gathering system in 2000 as a way to establish 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 new Matli processing plant in 2006. In addition, the previous owner replaced a substantial portion of the equipment on our Worland gathering system, including the Worland processing plant and the fractionation facility in 1997. Our Bakken gathering system was constructed in 2004. Our $49.5 million expansion at our Badlands location will be completed in 2007. 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. 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 continue to experience increased levels of exploration, development and production activities as a result of favorable 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 $200.0 million bank credit facility contains a $191.0 million revolving facility for acquisitions and capital expenditures, of which approximately $43.9 million is available as of December 31, 2006, and a $9.0 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.

Business Strategies

We are 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 and our Woodford Shale 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.

Midstream Assets

Our natural gas gathering systems include approximately 1,844 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 575 miles of natural gas gathering pipelines, ranging from two inches to sixteen 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 25,331 Mcf/d for the year ended December 31, 2006. There are five gas compressor stations located within the gathering system, comprised of twelve units. The plant and compressor stations combined have an aggregate of approximately 12,400 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 198 miles of gathering pipelines. In the first quarter of 2007, we completed the installation of additional pipelines and compression facilities at our Eagle Chief gathering system and increased our current system capacity from approximately 30,000 Mcf/d to approximately 35,500 Mcf/d.

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, depending on delivery points, may not be required to be processed to meet pipeline quality specifications when we sell into interstate markets. The plant has processing capacity of approximately 35,000 Mcf/d. During the year ended December 31, 2006, the facility processed approximately 25,331 Mcf/d of natural gas and produced approximately 864 Bbls/d of NGLs.

Natural Gas Supply. As of December 31, 2006, 423 wells were connected to our Eagle Chief gathering system. These wells are located in the Anadarko Basin of northwestern Oklahoma and we believe they generally have long lives. The primary suppliers of natural gas to the Eagle Chief gathering system are Chesapeake Energy Corporation and CRI, which represented approximately 65% and 11%, respectively, of the Eagle Chief gathering system s natural gas supply for the year ended December 31, 2006.

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, percentage-of-index contracts or fee-based contracts. For the year ended December 31, 2006, approximately 62%, 35% and 3% of our total segment margin attributable to the Eagle Chief gathering system was derived from percentage-of-proceeds, percentage-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. This area has experienced increased levels of natural gas exploration, development and production activities as a result of higher realized 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 25,331 Mcf/d for December 2006. During the year ended December 31, 2006, we added 51 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 were OGE Energy Resources, Inc., ONEOK Hydrocarbon, LP, Chevron Natural Gas and BP Energy Company, which represented approximately 29%, 20%, 18% and 18%, respectively, of the revenues from such sales for the year ended December 31, 2006.

Bakken Gathering System

General. The Bakken gathering system is located in eastern Montana and consists of approximately 334 miles of natural gas gathering pipelines, ranging from three inches to twelve inches in diameter, the Bakken processing plant, which includes seven compressors and a fractionation facility. The gathering system has a capacity of approximately 25,000 Mcf/d, and average throughput was approximately 17,290 Mcf/d for the year ended December 31, 2006. There are three gas compressor stations located within the gathering system, comprised of five units. The compressor stations and plant combined have slightly over 10,600 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. For the year ended December 31, 2006, the facility processed approximately 17,290 Mcf/d of natural gas and produced approximately 1,742 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 year ended December 31, 2006, the facility fractionated an average of approximately 2,646 Bbls/d to produce approximately 974 Bbls/d of propane and approximately 724 Bbls/d of a mixture of butane and gasoline. In connection with the expansion of the gathering and compression infrastructure we completed in the fourth quarter of 2006 in which we increased the system s capacity from approximately 20,000 Mcf/d to 25,000 Mcf/d, we further intend to expand the existing NGL fractionation facilities at our Bakken processing plant in order to fractionate expected increased NGL volumes from both the Bakken processing plant and the Badlands processing plant. We expect this expansion will be completed in the second quarter of 2007.

Natural Gas Supply. As of December 31, 2006, 224 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 Enerplus Resources (USA) Corporation, CRI and Burlington Resources Trading, Inc., which represented approximately 48%, 40% and 12%, respectively, of the Bakken gathering system s natural gas supply for the year ended December 31, 2006.

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. During the year ended December 31, 2006, we added 81 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 SemStream, L.P. at the tailgate of the plant.

Our primary purchasers of residue gas and NGLs on the Bakken gathering system were Montana-Dakota Utilities Company and SemStream, L.P., which represented approximately 51%, and 43% respectively, of the revenues from such sales for the year ended December 31, 2006.

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 2,759 Mcf/d for the year ended December 31, 2006. There are seven gas compressor stations located within the gathering system, comprised of eleven units. The plant and compressor stations have a total of nearly 5,500 horsepower installed.

The Worland gathering system and the Worland processing plant were contributed to us on February 15, 2005 in connection with our formation and our initial public offering. This gathering 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 portions of the Worland processing plant 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 year ended December 31, 2006, the facility processed approximately 2,759 Mcf/d of natural gas and produced approximately 156 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 year ended December 31, 2006, the facility fractionated an average of approximately 299 Bbls/d to produce approximately 54 Bbls/d of propane and approximately 63 Bbls/d of a mixture of butane and gasoline.

Natural Gas Supply. As of December 31, 2006, 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 CRI and KCS Resources, Inc., which represented approximately 61% and 30%, respectively, of the Worland gathering system s natural gas supply for the year ended December 31, 2006.

The natural gas supplied to the Worland gathering system is generally dedicated to us under individually negotiated long-term contracts. Following the initial term of the contracts, they 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 percentage-of-index contracts and fixed fee contracts. For the year ended December 31, 2006, approximately 94% and 6% of our total segment margin attributable to the Worland gathering system was derived from percentage-of-index contracts and fixed fee 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 a subsidiary of Kinder Morgan Energy Partners, L.P. at the tailgate of the plant.

Our primary purchasers of residue gas and NGLs on the Worland gathering system were Rainbow Gas Company, a Kinder Morgan Energy Partners, L.P. subsidiary and Tenaska Marketing Ventures, which represented approximately 29%, 28% and 28%, respectively, of revenues from such sales on the Worland gathering system for the year ended December 31, 2006.

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 141 miles of natural gas gathering pipelines, ranging from two inches to eight inches in diameter, the Badlands processing plant, a natural gas treating facility, a fractionation facility and five gas compressor stations. The total horsepower for the system was about 5,900 at the end of 2006. The gathering system has a capacity of approximately 5,000 Mcf/d, and average throughput was approximately 2,489 Mcf/d for the year ended December 31, 2006.

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 year ended December 31, 2006, the facility processed approximately 2,489 Mcf/d of natural gas and produced approximately 270 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 year ended December 31, 2006, the facility fractionated an average of approximately 312 Bbls/d to produce approximately 95 Bbls/d of propane and approximately 114 Bbls/d of a mixture of butane and gasoline.

On February 1, 2006, we entered into a five-year definitive purchase agreement with a current producer to build additional compression facilities and to expand our existing gas gathering system into South Dakota. The gathering project was completed in the fourth quarter of 2006 at a cost of $3.1 million, which we funded using our existing bank credit facility.

On November 8, 2005, we entered into a new 15-year definitive gas purchase agreement with CRI under which we will gather, treat and process additional natural gas, which is produced as a by-product of CRI s 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, targeted for completion in the second quarter of 2007, is expected to cost approximately $40.0 million, with an additional investment of $9.5 million planned during the second half of 2007 to expand the system. We are funding this project using our existing bank credit facility, and as of December 31, 2006, we have invested approximately $31.7 million.

Natural Gas Supply. As of December 31, 2006, 106 wells were connected to our Badlands gathering system. These wells are located in the Williston Basin of southwestern North Dakota and northwestern South Dakota and generally have long lives with predictable and steady flow rates. The primary suppliers of natural gas to the Badlands gathering system are CRI, Luff Exploration Company and Burlington Resources, which represented approximately 44%, 28% and 21%, respectively, of the Badlands gathering system s natural gas supply for the year ended December 31, 2006.

The natural gas supplied to the Badlands gathering system is generally dedicated to us under individually negotiated long-term contracts. Our new agreement with CRI 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 36.0 Bcf of natural gas gathered. This agreement will replace our existing agreement with CRI in the area when the new plant becomes operational. Following the initial term of the contracts, they 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 our Badlands gathering system, we currently provide air compression and water injection services to CRI 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 the Williston Basin Intrastate 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 SemStream, L.P. at the tailgate of the plant.

Our primary purchasers of the residue gas, propane and NGLs from the Badlands gathering system were CRI, SemStream, L.P. and a Kinder Morgan Energy Partners, L.P. subsidiary, which represented approximately 33%, 28% and 27%, respectively, of the revenues from such sales for the year ended December 31, 2006.

Matli Gathering System

General. The Matli Gathering System is located in central Oklahoma and consists of approximately 52 miles of natural gas gathering pipelines, ranging from three inches to twelve inches in diameter, the Matli processing plant, and a natural gas treating facility and two gas compressor stations, all totaling approximately 6,950 horsepower. The gathering system has a capacity of approximately 25,000 Mcf/d, and average throughput was approximately 15,231 Mcf/d for the year ended December 31, 2006.

We commenced operation of the Matli gathering system in 1999. During the fourth quarter of 2006, we completed the construction of a 25,000 Mcf/d natural gas processing facility along our existing gas gathering system, which replaced our 10,000 Mcf/d processing facility we had constructed 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 new plant has processing capacity of approximately 25,000 Mcf/d. During the year ended December 31, 2006, the facilities processed approximately 8,986 Mcf/d of natural gas and produced approximately 216 Bbls/d of NGLs. The $3.1 million investment in the new processing facility was funded from borrowings on our bank credit facility.

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. The throughput capacity on our Matli treating facility is approximately 20,000 Mcf/d. During the year ended December 31, 2006, the facility treated approximately 8,686 Mcf/d of natural gas.

Natural Gas Supply. As of December 31, 2006, 48 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 CRI and Range Resources Corporation, which represented approximately 59% and 30%, respectively, of the Matli gathering system s natural gas supply for the year ended December 31, 2006.

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 five years with two 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. As part of our $3.1 million expansion project mentioned above, we converted an existing natural gas pipeline into a NGL pipeline and now transport NGLs to the ONEOK Hydrocarbon Medford facility.

Our primary purchasers of residue gas and NGLs on the Matli gathering system were OGE Energy Resources, Chevron Natural Gas and BP Energy, which represented approximately 41%, 18% and 26%, respectively, of the revenues from such sales for the year ended December 31, 2006.

Kinta Area Gathering Systems

General. The Kinta Area gathering systems, which Hiland Partners acquired from Enogex on May 1, 2006, are located in eastern Oklahoma and consist of five separate natural gas gathering systems with 573 miles of natural gas gathering pipelines ranging from four inches to twelve inches in diameter, 26 gas drive compressor units and one electric compressor unit capable of an aggregate of approximately 40,600 horsepower. The gathering system has a capacity of approximately 180,000 Mcf/d, and average throughput was approximately 134,140 Mcf/d for the eight-month period from May 1, 2006 through December 31, 2006. Currently, our operations are limited to the gathering, dehydration and compression of the natural gas supplied to the Kinta Area gathering systems and the redelivery of the compressed natural gas for a fixed fee. However, an increasing portion of the natural gas supplied to the Kinta Area gathering systems has a high carbon dioxide content, and consequently, we have begun the installation of four amine-treating facilities on two of the five systems to remove excess carbon dioxide levels from the gas gathered by these gathering systems. We expect this expansion will be completed by the end of the first quarter 2007. We also intend to install additional compression facilities to expand the current capacity by approximately 3,000 Mcf/d on these gathering systems. We expect this expansion will be completed by the end of the third quarter 2007.

Natural Gas Supply. As of December 31, 2006, approximately 689 wells were connected to our Kinta Area gathering systems. These wells, which are located in the Arkoma Basin of eastern Oklahoma, primarily produce natural gas from the Atoka, Cromwell, Booch, Hartshorne, Spiro, Fanshaw and Red Oak formations. The associated natural gas produced from these wells flows through our Kinta Area gathering systems. The primary suppliers of natural gas to this gathering system are BP America Production Company, Chesapeake Energy Marketing, Inc. and Chevron North America Exploration and Production Co., which represented approximately 49%, 11% and 7%, respectively, of the Kinta Area gathering system s natural gas supply for the period from May 1, 2006 through December 31, 2006.

The Kinta Area gathering systems are located in an active drilling area. Historically, Enogex has connected approximately 24 newly drilled wells to these systems on an annual basis. We believe that this high level of exploration and development activity in the area, including the Woodford shale play to the west of the existing system, 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. The natural gas supplied to the Kinta Area gathering systems is generally dedicated under individually negotiated term contracts. The initial term of such agreements is generally three years.

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 4 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 9 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 5 miles of pipeline.

Compression Assets

We completed construction of our Cedar Hills compression facility and acquired the Horse Creek compression facility in 2002. The Horse Creek compression facility is comprised of two units with an

aggregate of approximately 5,300 horsepower. The Cedar Hills compression facility is comprised of ten units with an aggregate of approximately 40,000 horsepower. The water injection plant has three pumps with a total of 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 CRI and are ultimately utilized by CRI in its oil and gas secondary recovery operations. For a description of the services agreement we entered into with CRI 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 Anadarko Petroleum Corp., Mustang Fuel Corporation, 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, our competitor is Enogex, Inc. Our primary competitor on the Kinta Area gathering systems is CenterPoint Energy Field Services. 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 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, 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 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. Our pipeline systems are largely excluded from these regulations and are not generally situated within areas that would be designated high consequence. Therefore, compliance with these regulations has not had a significant impact on our operations.

Employee Health and Safety. We are subject to the requirements of the Occupational Safety and Health Act, or 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 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. With respect to any consents, permits or authorizations that have not been obtained, we believe that these consents, permits or authorizations will be obtained reasonably soon, 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 produced water 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. We lease the surface lands on which our Matli processing plant and compressor station are located and we lease the surface lands on which our Kinta Area compressors 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 7,037 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

We have no employees. Prior to September 25, 2006, employees of our general partner, Hiland Partners GP, LLC, provided services to us. In connection with the initial public offering of Hiland Holdings, all of the employees of our general partner became employees of the general partner of Hiland Holdings, Hiland Partners GP Holdings, LLC. As of December 31, 2006, Hiland Partners GP Holdings, LLC had 95 full-time employees who provide services to us. 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.

Address, Internet Web site and Availability of Public Filings

We maintain our principal corporate offices at 205 West Maple, Suite 1100, Enid, Oklahoma 73701. Our telephone number is (580) 242-6040. Our Internet address is www.hilandpartners.com. We make the following information available free of charge on our Internet Web site:

- Annual Report on Form 10-K;
- Quarterly Reports on Form 10-Q;
- Current Reports on Form 8-K;
- Amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934;
- Charters for our Audit, Conflicts, and Compensation Committees;
- Code of Business Conduct and Ethics; and
- Code of Ethics for Chief Executive Officer and Senior Financial Officers

We make our SEC filings available on our Web site as soon as reasonably practicable after we electronically file such material with, or furnish such material to, the SEC. The above information is available in print to anyone who requests it.

Item 1A. Risk Factors

Limited partner interests are inherently different from capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. 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.

Risks Related to Our Business

Our failure to replace Randy Moeder, our current Chief Executive Officer, with an individual with the required level of experience and expertise in a timely manner, could have an adverse impact on our operations and business strategy.

On March 14, 2007, we announced that Randy Moeder intends to resign as Chief Executive Officer and director of both our general partner and the general partner of Hiland Holdings GP, LP to pursue other career opportunities. Mr. Moeder has agreed to remain in such positions for approximately six months. Mr. Moeder has served as the Chief Executive Officer of our general partner since our inception in October 2004 and has been involved with our predecessor businesses since April 1998. Harold Hamm, Chairman of the board of directors of our general partner, is heading up a committee to secure a replacement for Mr. Moeder. However, if we are unsuccessful in replacing Mr. Moeder with an individual with the required level of experience and expertise in a timely manner, our operations and business strategy could be materially and adversely affected.

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 or to service our debt securities.

You should be aware that the amount of cash we have available for distribution or to service our debt securities 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 have cash available for distributions or debt service during periods when we record losses and may not have cash available for distributions or debt service 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 or to service our debt securities.

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. Natural gas prices have been high in recent years compared to historical periods. 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 or service our debt securities 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) Anadarko Petroleum Corp., Mustang Fuel Corporation and Duke Energy Field Services LLC at our Eagle Chief gathering system, (2) Enogex, Inc. at our Matli gathering system, (3) Bear Paw Energy, a subsidiary of ONEOK Partners, L.P., at our Badlands and Bakken gathering systems and (4) CenterPoint Energy Field Services at the Kinta Area gathering system. 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 year ended December 31, 2006, CRI, Chesapeake Energy Corporation and Enerplus Resources (USA) Corporation supplied us with approximately 33%, 24% and 12% respectively, of our total natural gas volumes purchased. BP Energy and Chesapeake Energy Corporation supplied us with approximately 49% and 11% respectively, of our natural gas volumes gathered. 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 or to service our debt securities.

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 or to service our debt securities.

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 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.

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. 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 FERC regulation under the 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) RCRA and comparable state laws that impose requirements for the discharge of waste from our facilities and (iii) 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 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 acquisition of the Kinta Area gathering assets, 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 approach 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.

Our ability to engage in construction projects and to make acquisitions will require access to a substantial amount of capital.

Our ability to engage in construction projects or to make acquisitions is dependent on obtaining adequate sources of outside financing, including commercial borrowings and other debt and common unit issuances. While the initial funding of our acquisitions may consist of debt financing, our financial strategy is to finance acquisitions approximately equally with equity and debt, and we would expect to repay such debt with proceeds of equity issuances to achieve this relatively balanced financing ratio. If we are unable to finance our growth through external sources or are unable to achieve our targeted debt/equity ratios, or if the cost of such financing is higher than expected, we may be required to forgo certain construction projects or acquisition opportunities or such construction projects or acquisition opportunities may not result in expected increases in distributable cash flow. Accordingly, our inability to obtain adequate sources of financing on economically acceptable terms may limit our growth opportunities, which could have a negative impact on our cash available to pay distributions.

Cost reimbursements due to our general partner may be substantial and will reduce cash available for distribution to holders of our common units or to service our debt securities.

Prior to making any distribution on our common units, we will reimburse our general partner for expenses it incurs on our behalf. The reimbursement of expenses could adversely affect our ability to pay cash distributions to holders of our common units. Our general partner will determine the amount of these expenses. In addition, our general partner and its affiliates may perform other services for us for which we will be charged fees as determined by our general partner.

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. At December 31, 2006, our total outstanding long-term indebtedness was approximately $147.1 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.

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

We rely exclusively on the revenues generated from our gathering, dehydration, treating, processing, fractionation and compression 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 to make acquisitions, reduce debt or finance internal growth projects.

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 finance internal growth projects.

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 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 and his affiliates control 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.

Harold Hamm and his affiliates control Hiland Partners GP Holdings, LLC, the general partner of Hiland Holdings, a publicly traded Delaware limited partnership that directly or indirectly owns 100% of our general partner. As a result, Harold Hamm and his affiliates control our general partner, which has sole responsibility for conducting our business and managing our operations. Conflicts of interest may arise between Harold Hamm and his 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 controls CRI; neither our partnership agreement nor any other agreement requires CRI 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 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.

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.

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 and its affiliates 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.

Harold Hamm and CRI may engage in limited competition with us.

Harold Hamm and CRI 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 CRI) 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 Harold Hamm and his affiliates no longer control us;

- the death of Harold Hamm; and

- February 15, 2010, the fifth anniversary of the closing of our initial public offering.

In addition, in connection with the initial public offering of Hiland Holdings, Hiland Holdings and its general partner entered into a non-competition agreement with us pursuant to which Hiland Holdings and its general partner have agreed that they will not, and they will cause any person or entity controlled by Hiland Holdings or its general partner (other than our general partner, our subsidiaries and us) 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. The non-competition agreement has the same permitted exceptions as the omnibus agreement and will terminate on the first day on which neither Hiland Holdings nor its general partner control us.

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 are unable initially to remove the general partner without its consent because the general partner and its affiliates own sufficient units to be able to prevent removal. The vote of the holders of at least 66⅔% of all outstanding units voting together as a single class is required to remove the general partner. As of March 5, 2007, affiliates of the general partner owned 57.8% 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. 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 determines 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.

All of the membership interests in our general partner and all of the common and subordinated units in us that are owned by Hiland Holdings are pledged as security under Hiland Holdings credit facility. Upon an event of default under Hiland Holdings credit facility, a change in ownership or control of us could ultimately result.

The 100% membership interest in our general partner and the 1,301,471 common units and 4,080,000 subordinated units in us that are owned by Hiland Holdings are pledged under Hiland Holdings credit facility. Hiland Holdings credit facility contains customary and other events of default. Upon an event of

default, the lenders under Hiland Holdings credit facility could foreclose on Hiland Holdings assets, which could ultimately result in a change in control of our general partner and a change in the ownership of our units held by Hiland Holdings.

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. As of March 5, 2007, affiliates of our general partner owned approximately 24.9% of the common units and, at the end of the subordination period, assuming no additional issuances of common units, affiliates of our general partner will own approximately 57.8% of the common units.

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.

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

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat us as a corporation or if we become subject to a material amount of entity-level taxation for state tax purposes, it would reduce the amount of cash available for distribution to you.

The anticipated after-tax economic benefit of an investment in our 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 taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income tax at varying rates. Distributions to you would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to you would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash 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 and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we will be subject to a new entity level tax on the portion of our income that is generated in Texas beginning in our tax year that ends December 31, 2007. Specifically, the Texas margin tax will be imposed at a maximum effective rate of 0.7% of our gross income apportioned to Texas. Imposition of such a tax on us by Texas, or any other state, will reduce the cash available for distribution to you.

Our 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 amounts will be adjusted to reflect the impact of that law on us.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution to you.

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 some or 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 your share of our income 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 actual tax liability that results from that income.

Tax gain or loss on disposition of our 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. Because distributions in excess of your allocable share of our net taxable income decrease your tax basis in your common units, the amount, if any, of such prior excess distributions with respect to the common units you sell will, in effect, become taxable income to you if you sell such common units at a price greater than your tax basis in those common units, even if the price you receive is less than your original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes your share of nonrecourse liabilities 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 our 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), 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 foreign person, you should consult your tax advisor before investing in our common units.

We will treat each purchaser of 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 adopt 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 your sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns.

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

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income.

You will likely be subject to state and local taxes and return filing requirements in states where you do not live as a result of investing in our common units.

In addition to federal income taxes, you will likely be subject to other taxes, including 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 various jurisdictions. Further, you may be subject to penalties for failure to comply with those requirements. We currently do business or own property in Mississippi, Montana, North Dakota, Oklahoma, Texas and Wyoming. Each of these states, except Texas and Wyoming currently impose a personal income tax. As we make acquisitions or expand our business, we may own assets or conduct 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 our common units.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

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

Item 4. Submission of Matters to a Vote of Security Holders

None.

PART II

Item 5. Market for Registrant s Common Units and Related Unitholder Matters and Issuer Purchases of Equity Securities

Our limited partner common units began trading on the Nasdaq National Market under the symbol HLND commencing with our initial public offering on February 10, 2005 at an initial public offering price of $22.50 per common unit. As of March 5, 2007, the market price for the common units was $53.02 per unit and there were approximately 3,900 common unitholders, including beneficial owners of common units held in street name and one record holder of our subordinated units. There is no established public trading market for our subordinated units. We intend to consider cash distributions to unitholders on a quarterly basis, although there is no assurance as to the future cash distributions since they are dependent upon future earnings, cash flows, capital requirements, financial condition and other factors. Our ability to distribute available cash is contractually restricted by the terms of our credit facility. Our credit facility contains covenants requiring us to maintain certain financial ratios. We are prohibited from making any distributions to unitholders if the distribution would cause an event of default, or an event of default exists, under our credit facility. Please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Description of Indebtedness Credit Facility.

The following table shows the high and low prices per common unit, as reported by the NASDAQ National Market, for the periods indicated. Cash distributions shown were paid within 45 days after the end of each quarter.

	Common Unit Price Ranges High	**Low**	**Cash Distribution Paid Per Unit(a)**
Year Ended December 31, 2006			
Quarter Ended December 31	$ 56.86	$ 44.00	$ 0.7125
Quarter Ended September 30	$ 47.33	$ 42.00	$ 0.7000
Quarter Ended June 30	$ 46.58	$ 41.21	$ 0.6750
Quarter Ended March 31	$ 43.95	$ 36.84	$ 0.6500
Year Ended December 31, 2005			
Quarter Ended December 31	$ 46.47	$ 34.50	$ 0.6250
Quarter Ended September 30	$ 46.22	$ 34.58	$ 0.5125
Quarter Ended June 30	$ 37.32	$ 31.17	$ 0.4625
Quarter Ended March 31	$ 35.00	$ 27.50	$ 0.2250 (b)

(a) For each quarter, an identical per unit cash distribution was paid on all outstanding subordinated units.

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

Cash Distribution Policy

Within 45 days after the end of each quarter, we will distribute all of our available cash (as defined in our partnership agreement) to unitholders of record on the applicable record date. The amount of available cash generally is all cash on hand at the end of the quarter less the amount of cash reserves established by our general partner to provide for the proper conduct of our business, to comply with applicable law, any of our debt instruments, or other agreements, or to provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters. Working capital borrowings are generally borrowings that are made under the working capital portion of our credit facility and in all cases are used solely for working capital purposes or to pay distributions to partners.

Upon the closing of our initial public offering, affiliates of Harold Hamm, the Hamm Trusts and an affiliate of Randy Moeder, our Chief Executive Officer, received an aggregate of 4,080,000 subordinated units. 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 quarter, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. The purpose of the subordinated units is to increase the likelihood that during the subordination period there will be available cash to be distributed on the common units. The subordination period will extend until the first day of any quarter beginning after 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 in its partnership agreement) generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum of the minimum quarterly distributions on all of the outstanding common 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. If the unitholders remove the general partner without cause, the subordination period may end before March 31, 2010.

In addition, 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.

We will make distributions of available cash from operating surplus for any quarter during any subordination period in the following manner: first, 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding common unit an amount equal to the minimum quarterly distribution for that quarter; second, 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding common unit an amount equal to any arrearages in payment of the minimum quarterly distribution on the common units for any prior quarters during the subordination period; third, 98% to the subordinated unitholders, pro rata, and 2% to the general partner, until we distribute for each subordinated unit an amount equal to the minimum quarterly distribution for that quarter; and thereafter, cash in excess of the minimum quarterly distributions is distributed to the unitholders and the general partner based on the percentages below.

Our general partner, Hiland Partners GP, LLC, is entitled to incentive distributions if the amount we distribute with respect to any quarter exceeds specified target levels shown below:

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

The equity compensation plan information required by Item 201(d) of Regulation S-K in response to this item is incorporated by reference into Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters, of this annual report on Form 10-K.

Issuer Purchases of Equity Securities

We did not repurchase any of our common units during the fourth quarter of fiscal 2006.

Item 6. Selected Historical Financial and Operating Data

The following table sets forth selected historical financial and operating data of Hiland Partners, LP and our predecessor, CGI as of and for the periods indicated. The selected historical financial data as of December 31, 2006 and for the years ended December 31, 2006 and 2005 are derived from the audited financial statements of Hiland Partners, LP. The selected historical financial data for the years ended December 31, 2004, 2003 and 2002 are derived from the audited financial statements of CGI.

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 costs of crude oil purchased by us from third parties. We define compression segment margin as the lease payments received under our compression facilities lease agreement with CRI which was restructured as described in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Items Impacting Comparability of Our Financial Results Restructuring of Compression Facilities Lease . 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.

The table should be read together with Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

	Hiland Partners, LP Year Ended December 31,		Predecessor Continental Gas, Inc.		
	2006	2005	2004	2003	2002
	(in thousands, except per unit and operating data)				
Summary of Operations Data:					
Total revenues	$ 219,686	$ 166,601	$ 98,296	$ 76,018	$ 35,228
Operating costs and expenses:					
Midstream purchases (exclusive of items shown separately below)	156,193	133,089	82,532	67,002	27,935
Operations and maintenance expenses	16,071	7,359	4,933	3,714	3,509
Depreciation, amortization and accretion	22,130	11,112	4,127	3,304	2,370
Property impairment expense				1,535	
(Gain) loss on asset sales			(19)	34	(12)
Bad debt expense					295
General and administrative expenses	4,994	2,470	1,082	770	730
Total operating costs and expenses	199,388	154,030	92,655	76,359	34,827
Operating income (loss)	20,298	12,571	5,641	(341)	401
Other income (expense):					
Interest expense	(5,532)	(1,942)	(702)	(473)	(185)
Amortization of deferred loan costs	(407)	(484)	(102)	(24)	
Interest income and other	323	192	40	10	72
Total other income (expense)	(5,616)	(2,234)	(764)	(487)	(113)
Income (loss) from continuing operations	14,682	10,337	4,877	(828)	288
Discontinued operations, net			35	246	199
Income (loss) before change in accounting principle	14,682	10,337	4,912	(582)	487
Cumulative effect of change in accounting principle				1,554	
Net income	$ 14,682	$ 10,337	$ 4,912	$ 972	$ 487
Net income per limited partner unit basic(1)	$ 1.37	$ 1.33			
Net income per limited partner unit diluted(1)	$ 1.36	$ 1.32			
Cash distributions per limited partner unit(2)	$ 2.74	$ 1.83			
Balance Sheet Data (at period end):					
Property and equipment, at cost, net	$ 252,801	$ 120,715	$ 37,075	$ 38,425	$ 23,722
Total assets	343,816	193,969	49,175	47,840	28,058
Accounts payable affiliates	4,412	6,122	2,998	2,814	2,150
Long-term debt, net of current maturities	147,064	33,784	12,643	14,571	3,491
Net equity	167,746	138,589	24,510	21,739	20,767
Cash Flow Data:					
Net cash flow provided by (used in):					
Operating activities	$ 39,580	$ 8,122	$ 7,957	$ 4,464	$ 4,809
Investing activities	(158,426)	(74,888)	(5,290)	(17,286)	(5,645)
Financing activities	123,045	72,736	(2,946)	13,212	516
Other Financial Data:					
Midstream segment margin	$ 58,674	$ 29,295	$ 15,764	$ 9,016	$ 7,293
Compression segment margin	4,819	4,217			
Total segment margin	$ 63,493	$ 33,512	$ 15,764	$ 9,016	$ 7,293
EBITDA	$ 42,751	$ 23,875	$ 9,843	$ 4,773 (3)	$ 3,042
Maintenance capital expenditures	$ 3,434	$ 2,225	$ 1,693	$ 1,769	$ 1,826
Expansion capital expenditures	155,103	72,723	3,474	14,900	3,244
Discontinued operations			159	745	690
Total capital expenditures	$ 158,537	$ 74,948	$ 5,326	$ 17,414	$ 5,760
Operating Data:					
Natural gas sales (MMBtu/d)	66,947	47,096	40,560	37,701	26,599
NGL sales (Bbls/d)	3,347	1,965	1,133	895	950
Natural gas gathered (MMBtu/d)	85,540				

(1) Net income per unit is not applicable for periods prior to our initial public offering.

(2) Includes our cash distributions of $0.7125 per unit paid on February 14, 2007 for 2006 and $0.625 per unit paid on February 14, 2006 for 2005.

(3) EBITDA has not been (a) increased for the impact of the $1.5 million non-cash impairment charge for the year ended December 31, 2003 or (b) decreased for the $1.6 million cumulative effect of accounting change for the year ended December 31, 2003.

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 for each of the periods indicated.

	Hiland Partners, LP Year Ended December 31,		Predecessor Continental Gas, Inc.		
	2006	2005	2004	2003	2002
	(in thousands)				
Reconciliation of EBITDA to Net Income:					
Net income	$ 14,682	$ 10,337	$ 4,912	$ 972	$ 487
Add:					
Depreciation, amortization and accretion	22,130	11,112	4,127	3,304	2,370
Amortization of deferred loan costs	407	484	102	24	
Interest expense	5,532	1,942	702	473	185
EBITDA	$ 42,751	$ 23,875	$ 9,843	$ 4,773 (1)	$ 3,042
Reconciliation of Total Segment Margin to Operating Income (Loss)					
Operating income (loss)	$ 20,298	$ 12,571	$ 5,641	$ (341)	$ 401
Add:					
Operations and maintenance expenses	16,071	7,359	4,933	3,714	3,509
Depreciation, amortization and accretion	22,130	11,112	4,127	3,304	2,370
Property impairment expense				1,535	
(Gain) loss on asset sales			(19)	34	(12)
Bad debt expense					295
General and administrative expenses	4,994	2,470	1,082	770	730
Total segment margin	$ 63,493	$ 33,512	$ 15,764	$ 9,016	$ 7,293

(1) EBITDA has not been (a) increased for the impact of the $1.5 million non-cash impairment charge for the year ended December 31, 2003 or (b) decreased for the $1.6 million cumulative effect of accounting change for the year ended December 31, 2003.

Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations

You should read the following discussion in conjunction with our Consolidated Financial Statements and notes thereto included elsewhere in this report.

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 CGI and Hiland Partners, LLC.

CGI historically owned all of our natural gas gathering, processing, treating and fractionation assets other than our Worland and Bakken gathering systems and the Kinta Area gathering systems we acquired on May 1, 2006. Hiland Partners, LLC historically has owned our Worland gathering system, our compression services assets and the Bakken gathering system. CGI 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 CGI.

In connection with our initial public offering, the former owners of CGI and Hiland Partners, LLC and certain of our affiliates, including our general partner, contributed to us, all of the assets and operations of CGI, 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.

We completed a follow-on offering of 1,630,000 common units on November 21, 2005, receiving net proceeds of $66.1 million including our general partner s contribution of $1.4 million. We used $65.2 million of the proceeds from the public offering to repay a portion of credit facility borrowings we had previously used to fund the acquisition of Hiland Partners, LLC.

On May 1, 2006, we acquired Enogex Gas Gathering, L.L.C. s eastern Oklahoma Kinta Area gathering assets for $96.4 million. We financed the acquisition with $61.2 million of borrowings from our credit facility and $35.0 million of proceeds from the issuance to our general partner of 761,714 common units and 15,545 general partner equivalent units at $45.03 per unit.

On September 25, 2006, certain affiliated unitholders contributed (i) all of the membership interests in our general partner, which owns the 2% general partner interest and all of the incentive distribution rights in us and (ii) 1,301,471 common units (including 761,714 common units held by our general partner) and 4,080,000 subordinated units in us to Hiland Holdings GP, LP, a publicly owned limited partnership (NASDAQ: HPGP), in exchange for 13,550,000 limited partner units, representing a 62.7% ownership in

Hiland Holdings GP, LP. Hiland Partners GP Holdings, LLC, a Delaware limited liability company formed on May 10, 2006, is the general partner of Hiland Holdings GP, LP.

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. The midstream segment generated 92.4% of our total segment margin for the year ended December 31, 2006 and 87.4% of our total segment margin for the year ended December 31, 2005.

- *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. The compression segment generated 7.6% of our total segment margin for the year ended December 31, 2006 and 12.6% of our total segment margin for the year ended December 31, 2005. We had no compression segment prior to February 15, 2005.

Our midstream assets consist of 13 natural gas gathering systems with approximately 1,844 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.

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 CRI 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 CRI 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, combined with an increased need for corporate office employees as a result of acquisitions and internal growth. These expenses were approximately $5.0 million for 2006, $2.5 million for 2005 and $1.1 million for 2004. These increases were primarily due to increased wages and benefits as a result of growth, costs of tax return preparations, 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 we entered into with CRI in connection with our initial public offering on February 15, 2005, CRI agreed to provide technology support and human resource functions to us for two years, at the lower of CRI s cost to provide the services or $50,000 per year. During the third quarter of 2006, we hired a director of information technology and a director of human resources and transitioned these services away from CRI.

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;

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- 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. 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, we have the following forward sales contracts to sell natural gas on our Eagle Chief, Matli and Kinta Area gathering systems:

Production period	**(MMBtu)**	**Average Fixed Price (per MMBtu)**
January 2007 - December 2007	1,380,000	$ 6.92
January 2008 - December 2008	1,200,000	$ 8.43

We also use cash flow hedges to limit our exposure to changing natural gas prices. Under these hedges we settle monthly on the difference between the sales or purchases of future production to or from our counterparty at fixed prices and the price that will be established on the date of hedge settlement by reference to a specified index price. These hedge contracts cover periods of up to twenty-four months from the date of the hedge.

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. We also use cash flow hedges to limit our exposure to changing NGL prices. Under these hedges we settle monthly on the difference between the sales of future production to our counterparty at a fixed price and the price that will be established on the date of hedge settlement by reference to a specified index price. These hedges cover periods of up to fifteen months from the date of the hedge.

Hedging Contracts

To insure that our hedging financial instruments will be used solely for hedging price risks and not for speculative purposes, we continually review our hedges for compliance with our hedging policies and procedures. We recognize gains and losses from the settlement of our hedges in revenue when we either sell or buy the associated physical residue natural gas or sell the associated physical natural gas liquid. Any gain or loss realized as a result of hedging is substantially offset in the market when we either sell or buy the physical residue natural gas or sell the physical natural gas liquid. All of our hedges are characterized as cash flow hedges as defined in Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended. We determine gains or losses on open and closed hedging transactions based upon the difference between the hedge price and the physical price. For a more detailed discussion on our hedging activity, please read commodity price risks included in Item 7A Quantitative and Qualitative Disclosures about Market Risk .

Our Natural Gas Purchase and Gathering Contracts

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

The following is a summary of the four types of natural gas purchase contracts that accounted for the largest percentage of volumes purchased for the years ended December 31, 2006, 2005 and 2004.

- *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 an agreed upon percentage of the proceeds for the natural gas and the NGLs. Under these types of arrangements, our revenues and total segment margin correlate directly with increases or decreases in natural gas and NGL prices. For the years ended December 31, 2006, 2005 and 2004 we purchased 52%, 43% and 33% of our total volumes under these types of fee arrangements, respectively.

- *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 years ended December 31, 2006, 2005 and 2004 we purchased 17%, 25% and 31% of our total volumes under these types of fee arrangements, respectively.

- *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 years ended December 31, 2006, 2005 and 2004 we purchased 31%, 33% and 36% of our total volumes under these types of fee arrangements, respectively.

- *Fixed-fee gathering arrangements.* Under fixed-fee gathering arrangements, we gather, dehydrate and compress natural gas supplied to our gathering systems and redeliver the compressed natural gas for a fixed fee. Under these arrangements, we do not take title to the natural gas. From the period May 1, 2006 through December 31, 2006, we gathered an average of 134,140 MMBtu/d, which accounted for 56% of our total volumes.

We are a party to a fixed-fee gas purchase contract with CRI dated as of August 1, 1999. For the years ended December 31, 2006, 2005 and 2004 gas purchased under the contract represented approximately 12.5%, 14.0% and 12.9%, respectively of our aggregate natural gas supply. Under the contract, CRI 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 25 wells that are connected to our Matli gathering system. We pay CRI 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.

Compression Services Agreement

Under the compression services agreement that we entered into with CRI in connection with our initial public offering and effective as of January 28, 2005, CRI 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, CRI 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 CRI 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. CRI 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 CRI s failure to supply power or water or a force majeure. The agreement has an initial term ending January 28, 2009 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 CGI and Hiland Partners, LLC. As part of our formation, immediately prior to consummation of our initial public offering, the former owners of CGI and Hiland Partners, LLC contributed to us all of the assets and operations of CGI 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.

CGI 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 and the Kinta Area gathering systems we acquired on May 1, 2006. As a result, our historical financial statements for the periods prior to February 15, 2005 are the financial statements of CGI.

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.

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 CRI, pursuant to which Hiland Partners, LLC leased the facilities to CRI. CRI 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 CRI, 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 CRI for a fee. As part of the restructuring, the personnel at CRI 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, constructed the original Matli processing plant in 2003 and completed the construction of a new processing plant in 2006. 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. These 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.

We acquired the Kinta Area gathering assets in May 2006 and operate the gathering assets substantially differently than were operated by the previous owner. Since there was no sufficient continuity of the Kinta Area gathering assets operations prior to and after our acquisition, disclosure of prior financial information would not be material to an understanding of future operations. Therefore, the acquisition has been recorded as a purchase of assets and not of a business.

We are in the process of expanding 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, which is expected to be operational by the second quarter of 2007, and the expansion of our existing Badlands field-gathering infrastructure. We also entered into a five-year definitive purchase agreement with a producer and have constructed additional compression facilities and expanded our existing Badlands gas gathering system into South Dakota.

We have installed additional gathering and compression infrastructure at our Bakken gathering system to increase the system s capacity from approximately 20,000 Mcf/d to 25,000 Mcf/d and are in the process of expanding the existing NGL fractionation facilities at the processing plant to fractionate increased NGL volumes from both the Bakken processing plant and the Badlands processing plant.

We have completed the installation of additional pipelines and compression facilities and increased our system capacity at our Eagle Chief gathering system from approximately 30,000 Mcf/d to approximately 35,500 Mcf/d due to increased volumes on this system. We have also completed the construction of a 25,000 Mcf/d natural gas processing facility along our existing Matli gas gathering system. This new facility provides additional plant processing capacity for increased system volumes.

We are in the process of installing four amine-treating facilities at several of our Kinta Area gathering system locations to remove excess carbon dioxide levels from the natural gas.

In December 2006, we entered into an agreement to construct and operate gathering pipelines and related facilities associated with the development of a portion of the acreage owned by CRI in the Woodford shale play in the Arkoma Basin of southeastern Oklahoma. We plan to build a 40,000 Mcf/d refrigeration processing plant and install field gathering, compression and associated equipment. The new gathering system will be designed to provide low-pressure and highly reliable gathering, compression, dehydration, and processing services. The gathering infrastructure is expected to include more than 15,500 horsepower of compression to provide takeaway capacity in excess of 40,000 Mcf/d. Expected startup of the initial phase of the project should occur during the second quarter of 2007.

Our Results of Operations

Set forth in the tables below are financial and operating data for our predecessor, CGI, and us 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. Operations from our acquisition of the Bakken gathering system assets are reflected only from September 1, 2005. Operations from our acquisition of the Kinta Area gathering assets are reflected only from May 1, 2006.

	Year Ended December 31				
	2006	**2005**			**2004**
	Hiland Partners, LP (in thousands)	**Hiland Partners, LP(1)**	**Predecessor(2)**	**Total**	**Predecessor(2)**
Total Segment Margin Data:					
Midstream revenues	$ 214,867	$ 150,571	$ 11,813	$ 162,384	$ 98,296
Midstream purchases	156,193	123,342	9,747	133,089	82,532
Midstream segment margin	58,674	27,229	2,066	29,295	15,764
Compression revenues(3)	4,819	4,217		4,217	
Total segment margin(4)	$ 63,493	$ 31,446	$ 2,066	$ 33,512	$ 15,764
Summary of Operations Data:					
Midstream revenues	$ 214,867	$ 150,571	$ 11,813	$ 162,384	$ 98,296
Compression revenues	4,819	4,217		4,217	
Total revenues	219,686	154,788	11,813	166,601	98,296
Operating costs and expenses:					
Midstream purchases (exclusive of items shown separately below)	156,193	123,342	9,747	133,089	82,532
Operations and maintenance expenses	16,071	6,579	780	7,359	4,933
Depreciation and amortization expenses	22,130	10,600	512	11,112	4,127
Gain on asset sales					(19)
General and administrative expenses	4,994	2,304	166	2,470	1,082
Total operating costs and expenses	199,388	142,825	11,205	154,030	92,655
Operating income	20,298	11,963	608	12,571	5,641
Other income (expense), net	(5,616)	(2,119)	(115)	(2,234)	(764)
Income (loss) from continuing operations	14,682	9,844	493	10,337	4,877
Discontinued operations, net					35
Net income	$ 14,682	$ 9,844	$ 493	$ 10,337	$ 4,912
Operating Data:					
Natural gas sales (MMBtu/d)	66,947	48,509	37,052	47,096	40,560
NGL sales (Bbls/d)	3,347	2,071	1,206	1,965	1,133
Natural gas gathered (MMBtu/d)(5)	85,540				

(1) 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).

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

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

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

	Year Ended December 31 2006 Hiland Partners, LP	2005 Hiland Partners, LP(1)	Predecessor(2)	Total	2004 Predecessor(2)
	(in thousands)				
Operating income	$ 20,298	$ 11,963	$ 608	$ 12,571	$ 5,641
Add:					
Operations and maintenance expenses	16,071	6,579	780	7,359	4,933
Depreciation, amortization and accretion	22,130	10,600	512	11,112	4,127
Gain on asset sales					(19)
General and administrative expenses	4,994	2,304	166	2,470	1,082
Total segment margin	$ 63,493	$ 31,446	$ 2,066	$ 33,512	$ 15,764

(5) Natural gas gathered for fee (MMBtu/d) represents natural gas volumes gathered associated with the Kinta Area gathering assets we acquired on May 1, 2006 in which we do not take title to the gas.

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

Revenues. Total revenues (midstream and compression) were $219.7 million for the year ended December 31, 2006 compared to $166.6 million for the year ended December 31, 2005, an increase of $53.1 million, or 31.9%. This increase was primarily attributable to (i) increased volumes of 11,799 MMBtu/d of natural gas sales, and 1,267 Bbls/d of NGL sales attributable to our acquisition of the Bakken gathering system effective September 1, 2005, (ii) increased volumes of approximately 8,428 MMBtu/d of natural gas sales and 127,437 MMBtu/d of natural gas gathered for the eight months ended December 31, 2006 from the Kinta Area gathering assets we acquired on May 1, 2006, (iii) additional volumes attributable to the Worland gathering system which was contributed to us on February 15, 2005 and (iv) increased revenues from compression assets also contributed to us on February 15, 2005.

Midstream revenues were $214.9 million for the year ended December 31, 2006 compared to $162.4 million for the year ended December 31, 2005, an increase of $52.5 million, or 32.2%. Of this net increase, $137.6 million was attributable to higher residue natural gas and NGL sales volumes offset by a decrease of $85.1 million attributable to decreased average realized natural gas and NGL prices. Increased volumes in 2006 on the Bakken gathering system we acquired effective September 1, 2005 and on the Kinta Area gathering assets we acquired on May 1, 2006 represented $41.1 million and $19.7 million, respectively of the increase in midstream revenues. This combined increase of $60.8 million was primarily offset by a decrease of $8.3 million as a result of lower natural sales gas and NGL sales prices in 2006 as compared to 2005.

Natural gas sales volumes were 66,947 MMBtu/d for the year ended December 31, 2006 compared to 47,096 MMBtu/d for the year ended December 31, 2005, an increase of 19,851 MMBtu/d, or 42.2%. Of the 19,851 MMBtu/d increase, 11,799 MMBtu/d, or 59.4% was attributable to natural gas volumes as a result of our Bakken gathering system acquisition effective September 1, 2005 and 5,657 MMBtu/d, or 32.1% was

attributable to the natural gas volumes as a result of our Kinta Area gathering assets we acquired on May 1, 2006. Our NGL sales volumes were 3,347 Bbls/d for the year ended December 31, 2006 compared to 1,965 Bbls/d for the year ended December 31, 2005, an increase of 1,385 Bbls/d, or 70.3%. Of the 1,382 Bbls/d increase, 1,267 Bbls/d, or 91.7% was attributable to our Bakken gathering system. Increased volumes at our Eagle Chief gathering system of 3,532 MMBtu/d and 126 Bbls/d also contributed to our overall increase in volumes for 2006 as compared to 2005.

Average realized natural gas sales prices were $5.64 per MMBtu for the year ended December 31, 2006 compared to $7.39 per MMBtu for the year ended December 31, 2005, a decrease of $1.75 per MMBtu, or 23.7%. Average realized NGL sales prices were $0.94 per gallon for the year ended December 31, 2006 compared to $1.01 per gallon for the year ended December 31, 2005, a decrease of $0.07 per gallon or 6.9%. The decreased in both our average realized natural gas sales prices and our NGL sales prices was primarily a result of lower index prices due to a softening of supply and demand fundamentals for energy, which caused natural gas and crude oil prices to fall during the year ended December 31, 2006 compared to the year ended December 31, 2005.

Cash received from our counterparty on cash flow swap contracts that began on May 1, 2006 for natural gas derivative transactions that closed during the year ended December 31, 2006 totaled $3.6 million. This gain increased average realized natural gas sales prices to $5.64 per MMBtu from $5.46 per MMBtu, an increase of $0.18 per MMBtu, or 3.3%. We had no closed derivative transactions during the year ended December 31, 2005.

Fees earned from an eight-month average of 127,437 MMBtu/d of natural gas gathered, in which we do not take title to the gas, related to our Kinta Area gathering assets we acquired on May 1, 2006 were $7.2 million for the year ended December 31, 2006. The eight-month average of 127,437 MMBtu/d equates to an average 85,540 MMBtu/d for the year ended December 31, 2006. We had no similar fees from natural gas gathering during the year ended December 31, 2005.

Compression revenues were $4.8 million for the year ended December 31, 2006 compared to $4.2 million for the year ended December 31, 2005, an increase of $0.6 million or 14.3%. The compression assets were contributed to us by Hiland Partners, LLC on February 15, 2005. Accordingly, revenues from these assets were only included for ten and one-half months of the year ended December 31, 2005.

Midstream Purchases. Midstream purchases were $156.2 million for the year ended December 31, 2006 compared to $133.1 million for the year ended December 31, 2005, an increase of $23.1 million, or 17.4%. Purchases increased by $25.9 million as a result of increased natural gas and NGL volumes as a result of our Bakken gathering system acquisition effective September 1, 2005 and by $9.3 million from increased natural gas volumes from our Kinta Area gathering assets acquisition which began on May 1, 2006. This combined increase of $35.2 million was primarily offset by $12.1 million in reduced payments to producers due to lower natural gas and NGL purchase prices, which generally are closely related to fluctuations in natural gas and NGL sales prices.

Operations and Maintenance. Operations and maintenance expense totaled $16.1 million for the year ended December 31, 2006 compared with $7.4 million for the year ended December 31, 2005, an increase of $8.7 million, or 118.4%. Of this increase, $4.6 million, or 53.2% was attributable to operations and maintenance as a result of our Kinta Area gathering assets we acquired on May 1, 2006 and $2.4 million, or 27.2% was attributable to operations and maintenance at our Bakken gathering system we acquired effective September 1, 2005. Higher costs of chemicals and lube oil, combined with increased wages due to internal expansions caused an increase in operations and maintenance of $1.5 million in our Eagle Chief, Matli, Badlands and Worland gathering systems in 2006 as compared to 2005.

Depreciation, Amortization and Accretion. Depreciation, amortization and accretion expense totaled $22.1 million for the year ended December 31, 2006 compared with $11.1 million for the year ended

December 31, 2005, an increase of $11.0 million, or 99.2%. Of this increase, $5.3 million, or 48.5% was attributable to depreciation and amortization on our Kinta Area gathering assets we acquired on May 1, 2006 and $4.6 million, or 42.2% was attributable to depreciation and amortization on our Bakken gathering system we acquired effective September 1, 2005. Depreciation at our Eagle Chief, Matli, Badlands and Worland gathering systems increased by $0.5 million in 2006 as compared to 2005 as a result of internal capital expansions completed in 2006.

General and Administrative. General and administrative expense totaled $5.0 million for the year ended December 31, 2006 compared with $2.5 million for the year ended December 31, 2005, an increase of $2.5 million, or 102.2%. The increase is primarily attributable to increased salaries and additional staffing of $0.9 million as a result of growth and $0.8 million in Sarbanes-Oxley internal control compliance costs and audit and tax preparation fees.

Other Income (Expense). Other income (expense) totaled ($5.6) million for the year ended December 31, 2006 compared with ($2.2) million for the year ended December 31, 2005, an increase in expense of $3.4 million. Interest expense increased $3.6 million. The increase is primarily attributable to interest expense associated with borrowings of $61.2 million on our credit facility to partially finance the Kinta Area gathering assets we acquired on May 1, 2006, the interest expense associated with the partial financing of the acquisition of the Bakken gathering system effective September 1, 2005 and additional interest expense on $62.1 million invested in maintenance and expansion capital expenditure projects in 2006 as compared to $10.4 million in 2005.

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

Revenues. Our total revenues (midstream and compression) were $166.6 million for the year ended December 31, 2005 compared to $98.3 million for the year ended December 31, 2004, an increase of $68.3 million, or 69.5%. 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 $162.4 million for the year ended December 31, 2005 compared to $98.3 million for the year ended December 31, 2004, an increase of $64.1 million, or 65.2%. Of this increase, $40.9 million was attributable to higher average realized natural gas prices and NGL sales prices and $23.2 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 47,096 MMBtu/d for the year ended December 31, 2005 compared to 40,560 MMBtu/d for the year ended December 31, 2004, an increase of 6,536 MMBtu/d, or 16.1%. Our NGL sales volumes were 1,965 Bbls/d for the year ended December 31, 2005 compared to 1,133 Bbls/d for the year ended December 31, 2004, an increase of 832 Bbls/d, or 73.4%. 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 $7.39 per MMBtu for the year ended December 31, 2005 compared to $5.49 per MMBtu for the year ended December 31, 2004, an increase of $1.90 per MMBtu, or 34.6%. In addition, average realized NGL sales prices were $1.01 per gallon for the year ended December 31, 2005 compared to $0.76 per gallon for the year ended December 31, 2004, an increase of $0.25 per gallon or 32.9%. 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 year ended December 31, 2005 compared to the year ended December 31, 2004.

Our compression revenues were $4.2 million for the year ended December 31, 2005. The compression assets were contributed by Hiland Partners, LLC on February 15, 2005. CGI, our predecessor, did not have a compression segment, therefore, there were no compression revenues reported for the year ended December 31, 2004.

Midstream Purchases. Our midstream purchases were $133.1 million for the year ended December 31, 2005 compared to $82.5 million for the year ended December 31, 2004, an increase of $50.6 million, or 61.3%. This increase is primarily attributable to increased payments on percent of proceeds and percent of index producer contracts as a result of 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 $7.4 million for the year ended December 31, 2005 compared with $4.9 million for the year ended December 31, 2004, an increase of $2.4 million, or 49.2%. 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 $11.1 million for the year ended December 31, 2005 compared with $4.1 million for the year ended December 31, 2004, an increase of $7.0 million, or 169.3%. 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 effective September 1, 2005.

General and Administrative. Our general and administrative expense totaled $2.5 million for the year ended December 31, 2005 compared with $1.1 million for the year ended December 31, 2004, an increase of $1.4 million, or 128.3%. The increase is primarily attributable to approximately $0.4 million related expenses for adding staff as a result of our growth and approximately $0.7 million additional costs of being a public company.

Other Income (Expense). Our other income (expense) totaled ($2.2) million for the year ended December 31, 2005 compared with ($0.8) million for the year ended December 31, 2004, a increase in expense of $1.5 million, or 192.4%. 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.

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 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 favorable 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 will 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 2006, our margins increased due to increased volumes but decreased due to reduced natural gas prices and NGL prices, resulting in a net increase in margins. During 2005 and 2004, 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 2004 and 2003, this positive impact on our margins was 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

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

Cash Flows from Operating Activities. Our cash flows from operating activities increased by $31.5 million to $39.6 million for the year ended December 31, 2006 from $8.1 million for the year ended December 31, 2005. Approximately $19.7 million of the increase is attributable to higher net income plus depreciation and amortization during the year ended December 31, 2006 as compared to the year ended December 31, 2005. In addition, changes in working capital items exclusive of cash contributed $2.0 million to cash flows from operating activities during the year ended December 31, 2006 as compared to reducing cash flows from operating activities by $13.8 million for the year ended December 31, 2005. The use of cash in operating activities in 2005 was primarily a result of replenishing our accounts receivable after the closing of our initial public offering and increased accounts receivable as a result of higher realized prices for natural gas and NGLs at December 31, 2005. In connection with our formation, $9.1 million of CGI accounts receivables was retained by former owners of CGI. Accounts receivables increased at December 31, 2006 as compared to December 31, 2005 as a result of receivables related to our acquisition of the Kinta Area gathering assets, but were offset by decreased natural gas and NGL prices at December 31, 2006 as compared to natural gas and NGL prices at December 31, 2005. Accounts payable and accrued midstream purchases as of December 31, 2006 increased due to increased vendor payables relating to internal expansion and growth projects and additional accounts payable relating to the operations of the Kinta Area gathering assets acquired on May 1, 2006, both of which were offset by a reduction in midstream purchases payable due to reduced natural gas and NGL purchase prices at December 31, 2006 as compared to natural gas and NGL prices at December 31, 2005.

Cash Flows Used for Investing Activities. Cash flows used in investing activities, which represent investments in property and equipment and payments made for acquisitions, increased to $158.4 million from $74.9 million, an increase of $83.5 million for the year ended December 31, 2006 as compared to the year ended December 31, 2005. The increase is primarily a result of the Kinta Area gathering assets acquisition on May 1, 2006, the ongoing progress on our Badlands expansion project, continued growth at our Bakken gathering system and various other internal expansion projects.

Cash Flows from Financing Activities. Our cash flows from financing activities increased to $123.0 million for the year ended December 31, 2006 from $72.7 million for the year ended December 31, 2005. During the year ended December 31, 2006, we borrowed $113.3 million under our credit facility to partially fund the Kinta Area gathering assets acquisition on May 1, 2006 and to fund our internal expansion projects at Badlands, Kinta and Bakken. During the year ended December 31, 2006, we received capital contributions of $35.0 million from our general partner in exchange for the issuance of 761,714 common units and 15,545 general partner equivalent units and $1.3 million as a result of issuing common units due to the exercise of 47,533 vested unit options. During the year ended December 31, 2006, we incurred $0.9 million of debt issuance costs and distributed $25.6 million to our unitholders. 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, CGI repaid $1.1 million of its outstanding indebtedness.

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

Cash Flows from Operating Activities. Our cash flows from operating activities increased by $0.2 million to $8.1 million for the year ended December 31, 2005 from $7.9 million for the year ended

December 31, 2004. We received cash flows from customers of approximately $143.4 million due to increased prices for natural gas and NGLs and higher volumes sold in 2005, had cash payments to our suppliers and employees of approximately $133.9 and payment of interest expense of $1.4 million, net of amounts capitalized, resulting in cash received from our operating activities of approximately $8.1 million. Changes in cash receipts and payments are primarily due to the timing of collections at the end of our reporting periods. We collect and pay large receivables and payables at the end of each calendar month and the timing of these payments and receipts may vary by a day or two between month-end periods, causing these fluctuations. Increased natural gas and natural gas liquids prices together with the acquisition of the Bakken assets contributed to increases in accounts receivable, accrued midstream revenues, accounts payable and accrued midstream purchases during 2005. In connection with our formation, $9.1 million of accounts receivables of CGI was retained by the former owners of CGI. Net income for the year ended December 31, 2005 was $10.3 million, an increase of $5.4 million from a net income of $4.9 million for the year ended December 31, 2004. Our non-cash expenses increased by $7.3 million to $11.6 million in 2005 from $4.3 million in 2004.

Cash Flows Used for Investing Activities. Our cash flows used for investing activities, which represent investments in property and equipment, increased by $69.6 million to $74.9 million for the year ended December 31, 2005 from $5.3 million for the year ended December 31, 2004. Our acquisition of the Bakken gathering system assets totaled approximately $64.6 million.

Cash Flows from Financing Activities. Our cash flows from financing activities increased to $72.7 million for the year ended December 31, 2005 from ($2.9) million for the year ended December 31, 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, CGI 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 $0.5 million in debt issuance costs by amending our credit facility. In addition, our cash flows from financing activities for the year ended December 31, 2005 reflect a $27.8 million distribution 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 $7,000 to maintain its 2% interest in us as a result of our issuance of 8,000 restricted common units to non-employee board members of our general partner. On November 21, 2005, we completed our follow-on public offering of 1,630,000 common units, receiving net proceeds, including a $1.4 million contribution from our general partner to maintain its 2% interest in us, less underwriter discount of $3.4 million, of $66.1 million. Offering costs associated with our follow-on public offering totaled $0.6 million. Concurrent with the closing of our secondary public offering, we repaid $65.2 million of our credit facility borrowings we had previously used to fund the Bakken acquisition. During the fourth quarter of 2005, we borrowed $5.3 million under our credit facility to fund capital expansion projects. From February 15, 2005 through December 31, 2005, we distributed $8.3 million to our unitholders.

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.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of December 31, 2006, which include expansion projects on our Badlands and Kinta Area gathering systems, is presented below:

Type of Obligation	Payment Due by Period Total Obligation	Due in 2007	Due in 2008	Due in 2009	Due in 2010	Due in 2011	Thereafter
	(in thousands)						
Senior secured revolving credit facility(1)	$ 147,064	$	$	$	$	$ 147,064	$
Contracts on internal expansion projects(2)	12,532	11,203	326	325	326	325	27
Operating leases and service agreements	1,423	774	278	138	83	49	101
Total contractual cash obligations	$ 161,019	$ 11,977	$ 604	$ 463	$ 409	$ 147,438	$ 128

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

(2) Internal Expansion Projects

Badlands Expansion Project. On November 8, 2005, we entered into a new 15-year definitive gas purchase agreement with CRI under which we will gather, treat and process additional natural gas, which is produced as a by-product of CRI s 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 second quarter of 2007, is expected to cost approximately $49.5 million, including an additional $9.5 million to be invested later in 2007 to expand the system. We are currently funding this expansion project using our existing bank credit facility. Commitments on contracts related to the Badlands expansion project included in the table above are approximately $5.9 million. 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.

Kinta Area Treating Facilities. We are in the process of installing four amine-treating facilities at several of our Kinta Area gathering system locations to remove excess carbon dioxide from the natural gas. We are also installing additional compression facilities to expand the current capacity by approximately 3,000 Mcf/d on these gathering systems. We will invest approximately $6.0 million on these projects and expect that the projects will be completed by the end of the first quarter of 2007. Commitments on contracts related to these projects included in the table above are approximately $4.1 million. 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.

Financial Derivatives and Commodity Hedges. We have entered into certain financial derivative instruments that are classified as cash flow hedges in accordance with SFAS No. 133, as amended, and relate to forecasted sales in 2007 and 2008. We entered into these instruments to hedge the forecasted natural gas and NGL sales or purchases against the variability in expected future cash flows attributable to changes in market prices. The swap instruments are contractual agreements between a counterparty and us to exchange obligations of money as the underlying natural gas or NGLs are sold or purchased. Under these swap agreements, we either receive or pay a monthly net settlement that is determined by the difference between a fixed price and a floating price based on certain indices for the relevant contract period for the agreed upon volumes. The following table provides information about these financial derivative instruments for the periods.

Fixed Price Physical Forward Sales Contracts. We have executed various natural gas fixed price physical forward sales contracts on approximately 115,000 MMBtu per month for 2007 and 100,000 MMBtu per month for 2008 with fixed prices ranging from $4.49 to $9.13 per MMBtu in 2007 and $8.43 per MMBtu in 2008. These contracts have been designated as normal sales under SFAS No. 133 and are therefore not marked to market as derivatives. A summary of our fixed price physical forward sales contracts as of December 31, 2006 is presented in the table below:

Production period	**(MMBtu)**	**Average Fixed Price (per MMBtu)**
January 2007 - December 2007	1,380,000	$ 6.92
January 2008 - December 2008	1,200,000	$ 8.43

Off-Balance Sheet Arrangements. We had no significant off-balance sheet arrangements as of December 31, 2006.

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. 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. On June 8, 2006, we entered into a second amendment to our credit facility to, among other things, increase our borrowing base to $200 million and revise certain covenants. The facility currently consists of a $191.0 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 $9.0 million senior secured revolving credit facility to be used for working capital and to fund distributions (the revolving working capital facility).

In addition, our credit facility provides for an accordion feature, which permits us, if certain conditions are met, to increase the size of the revolving acquisition facility by up to an additional $150.0 million and allows for the issuance of letters of credit of up to $15.0 million in the aggregate. The credit facility will mature in May 2011. 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.

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 125 basis points per annum or (ii) LIBOR plus an applicable margin ranging from 150 to 225 basis points per annum based on our ratio of consolidated funded 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 25 to 50 basis points per annum based on our ratio of consolidated funded debt to EBITDA will be payable on the unused portion of the credit facility. During any step-up period (as defined below), the applicable margin with respect to loans under the credit facility will be increased by 35 basis points per annum and the unused commitment fee will be increased by 12.5 basis points per annum.

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 consolidated funded debt to EBITDA ratio of 4.0:1.0, provided that in the event we make certain permitted acquisitions or capital expenditures, the credit facility allows this ratio to increase to 4.75:1.0 for the following three fiscal quarters (a step-up period); and
- a minimum interest coverage ratio of 3.0:1.0.

The credit facility defines EBITDA as our consolidated net income, plus income tax expense, interest expense, depreciation and amortization expense, amortization of intangibles and organizational costs, non-cash unit based compensation expense, and adjustments for non-cash gains and losses on specified derivative transactions and for other extraordinary items.

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 December 31, 2006, we had $147.1 million outstanding under the credit facility and were in compliance with its financial covenants.

Recent Accounting Pronouncements

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities . SFAS No. 159 expands opportunities to use fair value measurement in financial reporting and permits entities to choose to measure many financial instruments and certain other items at fair value. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. We have not decided if we will early adopt SFAS No. 159 or if we will choose to measure any eligible financial assets and liabilities at fair value.

In September 2006, the FASB issued SFAS No. 157 Fair Value Measurements. SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP) such as fair value hierarchy used to classify the source of information used in fair value measurements (i.e., market based or non-market based) and expands disclosure about fair value measurements based on their level in the hierarchy. This Statement applies to derivatives and other financial instruments, which Statement 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended, requires be measured at fair value at initial recognition and for all subsequent periods. This Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. We will apply the provisions of the Statement prospectively in our first interim period in the fiscal year beginning on January 1, 2008 and we do not expect a change in our methodologies of fair value measurements.

In September 2006, the SEC staff issued Staff Accounting Bulletin No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements. SAB 108 was issued to provide consistency between how registrants quantify financial statement misstatements. Historically, there have been two widely used methods for quantifying the effects of financial statement misstatements. These methods are referred to as the roll-over and iron curtain method. The roll-over method quantifies the amount by which the current year income statement is misstated. Exclusive reliance on an income statement approach can result in the accumulation of errors on the balance sheet that may not have been material to any individual income statement, but which may misstate one or more balance sheet accounts. The iron curtain method quantifies the error as the cumulative amount by which the current year balance sheet is misstated. Exclusive reliance on a balance sheet approach can result in disregarding the effects of errors in the current year income statement that results from the correction of an error existing in previously issued financial statements. SAB 108 established an approach that requires quantification of financial statement misstatements based on the effects of the misstatement on each of the company s financial statements and the related financial statement disclosures. This approach is commonly referred to as the dual approach because it requires quantification of errors under both the roll-over and iron curtain methods. We applied SAB 108 in connection with the preparation of our annual financial statements for the year ending December 31, 2006 and we did not record an adjustment.

Significant Accounting Policies and Estimates

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 for compression services are recognized when the services under the agreement are performed. Revenues from oil and gas production (discontinued operations) were recorded in the month produced and title was transferred to the purchaser.

Depreciation and Amortization. Depreciation 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. Intangible assets consist of the acquired value of existing contracts to sell natural gas and other NGLs, compression contracts and identifiable customer relationships, which do not have significant residual value. The contracts are being amortized over their estimated lives of ten years.

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.

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, including intangible 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 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.

Share Based Compensation. In October 1995 the FASB issued SFAS No. 123, Share-Based Payment, which was revised in December 2004 (SFAS 123R). SFAS 123R requires that the compensation cost relating to share-based payment transactions be recognized in the financial statements and that cost be measured based on the fair value of the equity or liability instruments issued. We adopted

SFAS 123R as of January 1, 2006 and applied SFAS 123R using the permitted modified prospective method beginning as of the same date and our unearned deferred compensation of $289 as of January 1, 2006 has been eliminated against common unit equity. Prior to January 1, 2006 we recorded any unamortized compensation related to restricted unit awards as unearned compensation in equity. We expect no change to our cash flow presentation from the adoption of SFAS 123R since no tax benefits are recognized by us as a pass through entity.

We estimate the fair value of each option granted on the date of grant using the American Binomial option-pricing model. In estimating the fair value of each option, we use our peer group volatility averages as determined on the option grant dates. We calculate expected lives of the options under the simplified method as prescribed by the SEC Staff Accounting Bulletin 107 and have used a risk free interest rate based on the applicable U.S. Treasury yield in effect at the time of grant. Our compensation expense for these awards is recognized on the graded vesting attribution method. Units to be issued under our unit incentive plan may be from newly issued units. Prior to our adoption of SFAS 123R on January 1, 2006, we applied Accounting Principles Board Opinion No. 25 and related interpretations in accounting for our unit-based compensation awards.

Disclosure Regarding Forward-Looking Statements

This annual report on Form 10-K includes certain forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. 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, 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 the 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 under Item 7.

Management s Discussion and Analysis of Financial Condition and Results of Operations Risk Factors Related to our Business. 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.

Item 7A. 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 year ended December 31, 2006, 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.

For the Year Ended December 31, 2006
Natural Gas Price Change ($/MMBtu)

		$ 0.10	$ (0.10)
NGL Price	$ 0.01	$ 263,000	$ 93,000
Change ($/gal)	$ (0.01)	$ (134,000)	$ (356,000)

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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. As a result of these derivative contracts, we have hedged a portion of our expected exposure to natural gas prices and NGL prices in 2007 and 2008. 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 for the periods indicated:

Description and Production Period	Average Volume	Fixed Price	Fair Value Asset (Liability)
Natural Gas Sold Fixed for Floating Price Swaps	(MMBtu)	(per MMBtu)	
January 2007 - December 2007	1,620,000	$ 8.03	$ 4,634
January 2008 - December 2008	1,620,000	$ 8.00	1,955
			$ 6,589
Natural Gas Buy Fixed for Floating Price Swaps	(MMBtu)	(per MMBtu)	
January 2007 - December 2007	600,000	$ 8.87	$ (1,625)
January 2008 - March 2008	150,000	$ 8.87	(194)
			$ (1,819)
Natural Gas Liquids Sold Fixed for Floating Price Swaps	(Bbls)	(per Gallon)	
January 2007 - December 2007	152,652	$ 1.13	$ (204)
January 2008 - March 2008	38,163	$ 1.13	(97)
			$ (301)

In addition to the derivative instruments noted in the table above, we have executed various natural gas fixed price physical forward sales contracts on approximately 115,000 MMBtu per month for 2007 and 100,000 MMBtu per month for 2008 with fixed prices ranging from $4.49 to $9.13 per MMBtu in 2007 and $8.43 per MMBtu in 2008. These contracts have been designated as normal sales under SFAS No. 133 and are therefore not marked to market as derivatives. A summary of our fixed price physical forward sales contracts is presented in the table below:

Production period	(MMBtu)	Average Fixed Price (per MMBtu)
January 2007 - December 2007	1,380,000	$ 6.92
January 2008 - December 2008	1,200,000	$ 8.43

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 December 31, 2006, we had approximately $147.1 million of indebtedness outstanding under our credit facility. The impact of a 100 basis point increase or decrease in interest rates on this amount of debt would result in an increase or decrease in interest expense, and a corresponding decrease or increase in net income of approximately $1.5 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., Montana-Dakota Utility Company and SemStream, L.P. were our largest customers for the year ended December 31, 2006, accounting for approximately 20%, 15% and 14%, respectively, of our revenues. Consequently, changes within one or more of these companies operations have the potential to impact, both positively and negatively, our credit exposure. Our counterparty for all of our derivative instruments as of December 31, 2006 is BP Corporation North America, Inc.

Item 8. Financial Statements and Supplementary Data

The See our Financial Statements beginning on page F-1 for the information required by this Item.

Item 9. Changes in and Disagreements on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

(a) Evaluation of disclosure controls and procedures.

Our principal executive officer and principal financial officer have evaluated, as required by Rule 13a-15(b) under the Securities Exchange Act of 1934 (the Exchange Act), our disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of the end of the period covered by the annual report on Form 10-K. Based on that evaluation, the principal executive officer and principal financial officer concluded that the design and operation of our disclosure controls and procedures are effective in ensuring that information we are required to disclose in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms.

(b) Changes in internal control over financial reporting.

For a six-month period beginning May 1, 2006, the accounting processes related to the Kinta Area gathering assets we acquired on that date were performed under a transition agreement with the seller, Enogex Gas Gathering L.L.C. For this six-month period, internal controls over financial reporting relating to Enogex Gas Gathering L.L.C. s accounting processes were reviewed for completeness and accuracy on a monthly basis. Beginning on November 1, 2006, the accounting processes were assumed by us and became subject to the same internal controls over financial reporting established in our other gathering systems. There have been no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Internal Control Over Financial Reporting

See Managements Report on Internal Control over financial Reporting on page F-2.

Item 9B. Other Information

There have been no events that occurred in the fourth quarter of 2006 that would need to be reported on Form 8-K that have not been previously reported.

PART III

Item 10. Directors and Executive Officers of the Registrant

As is the case with many publicly traded partnerships, we do not have officers, directors or employees. Our operations and activities are managed by our general partner, Hiland Partners GP, LLC. References to our directors and officers are references to the directors and officers of Hiland Partners GP, LLC. Unitholders do not directly or indirectly participate in our management or operation. Our general partner owes a fiduciary duty to our unitholders, as limited by our partnership agreement.

Directors are elected for one-year terms. The following table shows information regarding the current directors and executive officers of Hiland Partners GP, LLC. On March 14, 2007, we announced that Randy Moeder intends to resign as Chief Executive Officer and director of both our general partner and the general partner of Hiland Holdings GP, LP to pursue other career opportunities. Mr. Moeder has agreed to remain in such positions for approximately six months. Harold Hamm, Chairman of the board of directors of our general partner, is heading up a committee to secure a replacement for Mr. Moeder.

Name	Age	Position with Hiland Partners GP, LLC
Harold Hamm	61	Chairman of the Board of Directors
Randy Moeder	46	Chief Executive Officer, President and Director
Ken Maples	44	Chief Financial Officer, Vice President Finance, Secretary and Director
Ron Hill	56	Vice President Business Development
Robert Shain	56	Vice President Operations and Engineering
Michael L. Greenwood	51	Director
Edward D. Doherty	71	Director
Rayford T. Reid	58	Director
Shelby E. Odell	67	Director
John T. McNabb, II	62	Director
Dr. David L. Boren	65	Director

Harold Hamm was elected Chairman of the Board of Directors of our general partner in October 2004 and serves as chairman 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 CGI 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 CRI 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 CGI since January 1995 and was Vice President from November 1990 to January 1995. Mr. Moeder was Senior Vice President and General Counsel of CRI 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 an inactive 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 CGI and Hiland Partners, LLC since February 2004. Mr. Maples was Director of Business Development and Manager of Investor Relations of CRI 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 a Masters of Business Administration degree from Louisiana State University.

Ron Hill was elected as Vice President of Business Development in January 2006. Mr. Hill has spent 29 years in the oil and natural gas industry with a 25-year focus in gas processing, midstream gas gathering, transportation and NGL marketing. From October 2001 until January 2006, Mr. Hill served as Vice President Gas Supply for Pioneer Gas Pipeline, Inc. in San Angelo, Texas. From November 1991 until October 2001, Mr. Hill was Senior Representative Business Development for Western Gas Resources, Inc. in Oklahoma City, Oklahoma and Midland, Texas. Prior to November 1991, Mr. Hill served in a variety of commercial roles for Union Texas Petroleum Corporation, Tipperary Corporation and Texaco, Inc.

Robert Shain was elected as our Vice President Northern Region Operations & Engineering in March 2006 and was appointed Vice President Operations and Engineering on June 5, 2006. Mr. Shain has over 30 years in the oil and gas industry. The majority of his experience has been in the engineering and operations of midstream natural gas gathering, compression, processing and treating, along with business development and marketing. From July 2003 until March 2006, Mr. Shain served as Vice President of Operations and Engineering for Seminole Gas Company, LLC (successor to Impact Energy, LTD) in Tulsa, Oklahoma. From May 1995 until July 2003 Mr. Shain served in a variety of commercial roles, most recently of which was Vice President of Commercial Services, for CMS Field Services, LLC (successor to Heritage Gas Services, LLC) also in Tulsa, Oklahoma, in which he was responsible for the development and management of operating and capital budgets.

Michael L. Greenwood was elected as a director of our general partner in February 2005, and serves as Chairman of the audit committee 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 Hiland Holdings GP, LP , 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 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 and serves as a member of our audit committee of the board of directors of our general partner. 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.

John T. McNabb, II was elected to serve as a director of our general partner in August 2006, and he serves as chairman of the conflicts committee and as a member of the compensation committee of the board of directors of our general partner. Mr. McNabb is the founder of Growth Capital Partners, LP, a merchant banking firm that provides financial advisory services to middle market companies throughout the United States, and has served as the chairman of its board of directors since 1992. Mr. McNabb has also served as a Principal of Southwest Mezzanine Investments, the investment affiliate of Growth Capital Partners, L.P, since 2001. From June 1990 to January 1992, he was a Managing Director of Bankers Trust Company, managing commercial banking, investment banking and financial advisory activities in the Southwest for Bankers Trust Company, and a director of BT Southwest, Inc., an affiliate of Bankers Trust New York Corporation. Mr. McNabb currently serves on the board of directors of Warrior Energy Services, Inc. and Willbros Group, Inc. He holds a Bachelor of Arts in History and a Masters of Business Administration from Duke University.

Dr. David L. Boren was elected to serve as a director of our general partner in August 2006, and he serves as a member of the conflicts committee of the board of directors of our general partner. Dr. Boren serves as President of the University of Oklahoma, a position he has held since November of 1994. Prior to becoming President of the university, he served in the United States Senate representing Oklahoma from 1979 to 1994. During his service in the Senate he was the longest serving Chairman of the U.S. Select Committee on Intelligence. From 1975 to 1979 Dr. Boren was Governor of Oklahoma. Before being elected Governor, he served 8 years in the Oklahoma House of Representatives. He engaged in the private practice of law from 1969 to 1974. He also served as a professor of Political Sciences at Oklahoma Baptist University from 1970 to 1974. In 1986 Dr. Boren founded the Oklahoma Foundation for Excellence, a private foundation which rewards and encourages excellence in public education. He continues to serve as its Chairman. He received his BA degree from Yale University in 1963, his Master s Degree in Economics from Oxford University in 1965 as a Rhodes Scholar and his Juris Doctorate Degree from the University of Oklahoma in 1968. He previously served as a director of ConocoPhillips Inc. and currently serves as a director of Texas Instruments, AMR Corporation and Torchmark Corporation.

Board Committees

The board appoints committees to help carry out its duties. In particular, the board committees work on key issues in greater detail than would be possible at full board meetings. Only non-employee directors may serve on the audit, compensation and conflicts committees. Each committee has a written charter. The charters are posted on our Web site and are available free of charge on request to the Secretary at the address given under Contact Us .

The table below shows the current membership of each board committee.

Name	Audit	Conflicts	Compensation
Mr. Hamm			C
Mr. Greenwood	C		
Mr. Doherty	*		
Mr. Reid			*
Mr. Odell	*		
Mr. McNabb, II		C	*
Dr. Boren		*	

C = Chairman

* = Member

Audit Committee

The audit committee of our general partner s board of directors is comprised of three non-employee members of the board. The committee is appointed by the board of directors to assist the board in fulfilling its oversight responsibilities. Its primary responsibility is to monitor the quality, integrity and reliability of the financial reporting process, review the adequacy of our systems of internal controls for financial reporting, legal compliance and ethics established by management and the board and review procedures for internal auditing. Responsibilities also include the appointment, compensation, retention and oversight of the work of the independent registered public accounting firm engaged to prepare the audit report or perform other audit, review or attest services. The committee reviews proposed audit plans for the year and the coordination of these plans with the independent registered public accounting firm. The committee also reviews the financial statements and other information contained in quarterly and annual Securities and Exchange Commission s (the SEC) reports with management and the independent registered public accounting firm to determine that the independent registered public accounting firm is satisfied with the disclosure and content of the financial statements. The committee shall have authority to obtain advice and assistance from internal or external legal, financial and other advisors.

The board has determined that all members of the committee are independent within the meaning of both the SEC rules and the National Association of Securities Dealers, Inc. (NASDAQ) listing standards. The board has further determined that all members are financially literate within the meaning of the NASDAQ standards and that Mr. Greenwood is an audit committee financial expert as defined in the SEC rules.

Conflicts Committee

The conflicts committee of our general partner s board of directors is comprised of two non-employee members of the board. The committee is appointed by the board of directors of our general partner to carry out the duties delegated by the board that relate to specific matters that the board believes may involve conflicts of interests between us and our affiliates, on the one hand and us and any other group member, any partner or any assignee, on the other hand. The committee is composed solely of two independent directors who are not unitholders, officers or employees of us or our general partner, officers, directors or employees of any affiliate or holders of any ownership interest in us other than our common units and who also meet the independence and experience standards established by NASDAQ and any applicable laws and regulations.

The committee shall advise the board on actions to be taken by us or matters related to us upon request of the board. The committee determines if the resolution of such conflicts of interest is fair and reasonable to us. 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 to us or to our unitholders. In connection with the committee s resolution of any conflict of interest, the committee is authorized to consider the relative interests of any party to such conflict, agreement, transaction or situation and the benefits and burdens relating to such interest, any customary or accepted industry practices and any customary or historical dealings with a particular person. The committee is also authorized to consider any applicable generally accepted accounting practices or principles and such additional factors as the committee determines in its sole discretion to be relevant, reasonable or appropriate under the circumstances.

With respect to any contribution of assets to the Partnership in exchange for Partnership securities, the committee, in determining whether the appropriate number of Partnership securities are being issued, may take into account, among other things, the fair market value of the assets, the liquidated and contingent liabilities assumed, the tax basis in the assets, the extent to which tax-only allocations to the transferor will protect the existing partners of the Partnership against a low tax basis, and such other factors as the committee deems relevant under the circumstances. The committee shall have authority to obtain advice and assistance from internal or external legal, financial and other advisors.

Compensation Committee

The compensation committee of our general partner s board of directors is comprised of three non-employee members of the board. The committee has overall responsibility for approving and evaluating the general partner s director and officer compensation plans, policies and programs.

The committee oversees the compensation for our senior executives, including their salary, bonus, and incentive and equity awards. The committee is responsible primarily for reviewing, approving and reporting to the board on major compensation and benefits plans, policies and programs of the company; reviewing and evaluating the performance and approving the compensation of senior executive officers; and overseeing management development programs, performance assessment of senior executives and succession planning. Other specific duties and responsibilities include: annually reviewing and approving corporate goals and objectives relevant to the chief executive officer (CEO) base compensation, incentive-compensation plans and equity-based plans; evaluating the CEO s performance in light of those goals and objectives, and recommending to the board either as a committee or together with the other independent directors, the CEO s compensation levels based on this evaluation; and producing the required annual report on executive compensation.

The compensation committee has the sole authority to retain, amend the engagement with, and terminate any compensation consultant to be used to assist it in the evaluation of director, CEO or officer compensation. The committee has sole authority to approve the consultant s fees and other retention terms and shall have authority to cause us to pay the fees and expenses of such consultants. The committee shall also have authority to obtain advice and assistance from internal or external legal, accounting or other advisors, to approve the fees and expenses of such outside advisors, and to cause us to pay the fees and expenses of such outside advisors.

Report of the Audit Committee for the Year Ended December 31, 2006

Our management is responsible for our internal controls and our financial reporting process. Grant Thornton LLP, our Independent Registered Public Accounting Firm for the year ended December 31, 2006, is responsible for performing an integrated audit of the effectiveness of internal control over financial reporting and management s assessment thereof and an independent audit of our consolidated financial statements in accordance with standards of the Public Company Accounting Oversight Board and to issue a report thereon. Our audit committee monitors and oversees these processes. Our audit committee, made up of members of our general partner s Board of Directors, recommends to the board of directors the selection of our independent registered public accounting firm.

Our audit committee has reviewed and discussed our audited consolidated financial statements with our management and the independent registered public accounting firm. Our audit committee has discussed with Grant Thornton LLP the matters required to be discussed by Statement on Auditing Standards No. 61, as amended, Communications with Audit Committees, including that firm s independence.

Members of the Audit Committee:
Michael L. Greenwood
Edward D. Doherty
Shelby E. Odell

Code of Ethics

Our general partner has adopted a Financial Officers Code of Ethics applicable to the Chief Executive Officer and the Chief Financial Officer, Controller and all other senior financial and accounting officers (the Senior Financial Officers) with regard to Partnership-related activities. This Code of Ethics contains the policies that relate to the legal and ethical standards of conduct that the Senior Financial Officers of our general partner are expected to comply with while carrying out their duties and responsibilities on behalf of the Company. The Code of Ethics also incorporates expectations of Senior Financial Officers that enable us to provide accurate and timely disclosure in our filings with the SEC and other public communications. The Code of Ethics is publicly available on our website under the Governance section (at www.hilandpartners.com) and is also available free of charge on request to the Secretary at the address given under Contact Us .

Section 16(a) Beneficial Ownership Reporting Compliance

Based on our records, except as hereinafter set forth, we believe that during 2006 all of such reporting persons complied with the Section 16(a) filing requirements applicable to them.

Item 11. Executive Compensation

COMPENSATION DISCUSSION AND ANALYSIS

Compensation Objectives and Philosophy

The executive compensation program of our general partner is designed to enable our general partner to execute our business objectives by attracting, retaining, and motivating the highest quality of executive talent and by rewarding superior performance. Performance management focuses on building competencies required for our business and achieving the highest level of contribution from each employee. Our compensation and benefits policies and practices are designed to motivate and reward officers and employees to achieve goals and objectives that are expected to lead to long-term enhancement of unitholder value, provide total compensation that is competitive within the market place and align individual compensation with competency and contribution so that performance, tied to measurable objectives and results, will be rewarded appropriately. We identify our marketplace as both publicly traded companies approximating our revenue and employee size, and the midstream and pipeline master limited partnerships within our peer group, including Atlas Pipeline Partners, LP, Copano Energy, LLC, Crosstex Energy, LP, Global Partners, LP, MarkWest Energy Partners, LP, Regency Energy Partners, LP and TransMontaigne Partners, LP. The compensation committee, established in May 2005 believes this definition of our marketplace provides a good benchmark for analyzing the competitiveness of our executive compensation program.

In addition to base salary, executive officers are compensated on a performance-oriented basis through the use of incentive compensation linking both annual and longer-term results. The annual incentive bonus permits team and individual performance to be recognized and is based, in part, on an evaluation of the contribution made by the officer to our performance. Equity compensation awards are included in the compensation program to reward executive officers for long-term strategic actions that increase our value and thus unitholder value and to link a significant amount of an executive s current and potential future net worth to our success. This use of equity compensation directly relates a portion of each executive officer s long-term remuneration to our unit price, and therefore aligns the executive s compensation with the interests of other unitholders. The discretionary granting of unit options, as well as the more limited use of restricted units, is used to: (1) recognize promotions of executives into positions of significant responsibilities; (2) recognize significant accomplishments of executives, particularly as the accomplishments impact growth, profits and/or competitive positioning; and (3) attract and retain high level executive talent.

Oversight of Executive Compensation Program

The compensation committee of our general partner administers our executive officer compensation program. The compensation committee is primarily responsible for reviewing, approving and reporting to the board on major compensation and benefits plans, policies and programs of the Partnership; reviewing and evaluating the performance and approving the compensation of senior executive officers; and overseeing management development programs, performance assessment of senior executives and succession planning. Other specific duties and responsibilities include: annually reviewing and approving corporate goals and objectives relevant to the chief executive officer (CEO) base compensation, incentive-compensation plans and equity-based plans; evaluating the CEO s performance in light of those goals and objectives, and recommending to the board, either as a committee or together with the other independent directors, the CEO s compensation levels based on this evaluation; and producing the required annual report on executive compensation. The compensation committee annually evaluates the effectiveness of the executive compensation program in meeting its objectives.

The CEO submits annual base compensation, incentive-compensation and equity-based compensation recommendations of senior executive officers below the CEO to the compensation committee based on each executive s contribution to our performance and each executive s responsibilities and management abilities. The compensation committee evaluates compensation with reference to our financial and non-financial performance and relative unitholder return for the prior fiscal year, competitive compensation data of executives of comparable companies in our marketplace, subjective evaluation of each executive s contribution to our performance and each executive s experience, responsibilities and management abilities. The compensation committee annually advises the board on the compensation to be paid to the executive officers and approves the compensation for executive officers.

The compensation committee has the sole authority to retain, amend the engagement with, and terminate any compensation consultant to be used to assist it in the evaluation of director, CEO and executive officer compensation, as appropriate. The committee has sole authority to approve the consultant s fees and other retention terms and shall have authority to cause us to pay the fees and expenses of such consultants. The committee shall also have authority to obtain advice and assistance from internal or external legal, accounting or other advisors, to approve the fees and expenses of such outside advisors, and to cause us to pay the fees and expenses of such outside advisors. The compensation committee did not engage a compensation consultant to assist it in determining executive compensation for our fiscal year ending December 31, 2006.

Elements of Compensation

Our general partner s executive compensation program currently consists of the following elements:

- base salaries;
- annual incentive cash bonus; and
- long-term incentive compensation.

Base Salaries

Base salary for executive officers is determined annually by an assessment of our overall performance, executive officer performance, changes in executive officer responsibilities and relevant marketplace data. While many aspects of performance can be measured in financial terms, the compensation committee also evaluates senior management in areas of performance that are more subjective. These areas include the development and execution of strategic plans, the exercise of leadership in the development of management and other employees, innovation and improvement in our business activities, as well as the executive s involvement in industry groups and in the communities that we serve. Our general partner seeks to compensate executives for their performance throughout the year with annual base salaries that are fair and competitive within our marketplace. Our general partner believes that executive base salaries should be targeted near the median of the range of salaries for executives in similar positions and with similar responsibilities at comparable companies in line with our compensation philosophy, depending on level of competency and contribution of each executive. Individual salaries are generally established in alignment with this target to ensure the attraction, development and retention of superior talent, as well as in relation to individual executive performance. Base salaries are reviewed annually to ensure continuing consistency with market levels and our level of financial performance during the previous fiscal year. Future adjustments to base salaries and salary ranges will reflect average movement in the competitive market as well as individual performance.

Base salaries in 2006 for the CEO, the Chief Financial Officer (CFO) and the past Vice President of Operations and Engineering were established in November 2005 and were set based on (1) the financial results of our first nine months of operations beginning on February 15, 2005, (2) base salaries of executive officers within our marketplace and (3) a subjective evaluation of each executive s contribution to our performance and each executive s experience, responsibilities and management abilities. As such, annual base salaries established for the CEO, the CFO and the past Vice President of Operations and Engineering for the period from November 2005 through October 2006 were $$225,000, $190,000 and $160,000, respectively. Also in November 2005, base salaries were established for an additional Vice President of Operations and Engineering ($160,000 per year) and a Vice President of Business Development ($150,000 per year) to join our executive management team in early 2006, primarily determined by the comparable base salaries of similar executives within our marketplace. In November 2006, based on base salaries of comparable executives of companies within our marketplace, evaluation of each executive s contribution to our performance and the financial results of our operations, the compensation committee set base salaries of $288,000 for our CEO and $225,000 for our CFO for the period from November 2006 through October 2007.

Annual Incentive Cash Bonus

Annual incentive cash bonuses are intended to compensate executive officers for achieving our annual financial goals and for achieving measurable individual annual performance objectives. Annual cash bonuses are 100% discretionary and are determined by our performance relative to financial goals and individual personal performance goals. The compensation committee approves the annual incentive award, if any, for the CEO and for each officer below the CEO level, based on the CEO s recommendations. Discretionary cash bonuses awarded to our CEO and CFO of $85,000 and $55,000, respectively in March 2006, were determined based on similar bonuses awarded to comparable executives within our marketplace and the subjective evaluation of each executive s contribution to our financial performance and each executive s responsibilities and management abilities. Discretionary cash bonuses for our four named executive officers are to be addressed at the compensation committee meeting to be held in March 2007.

Long-Term Incentive Compensation

Our general partner adopted the Hiland Partners, LP Long-Term Incentive Plan for the employees and directors of our general partner and the employees of its affiliates. The compensation plan is administered by the compensation committee of our general partner s board of directors and 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.

The long-term incentive compensation plan is designed to reward executives and other key employees for the attainment of financial goals and other performance objectives approved annually by the compensation committee and to encourage responsible and profitable growth while taking into account non-routine factors that may be integral to our success. Long-term incentive compensation in the form of equity grants of our common units, such as incentive unit option grants and grants of restricted units, are used to incent performance that leads to enhanced unitholder value, encourage retention and closely align the executive s interests with unitholders long-term interests. Equity grants provide a vital link between the long-term results achieved for our unitholders and the rewards provided to executives and other key employees. The equity grants we adopted upon the formation of our long-term incentive compensation plan were designed to be comparable with long-term incentive plans of other midstream and pipeline master limited partnerships.

Under the unit option grant agreement, granted options of common units vest and become exercisable in one-third increments on the anniversary of the grant date over three years. Vested options are exercisable within the option s contractual life of ten years after the grant date. Restricted units vest in quarterly increments over a four-year period from the date of issuance. Unvested unit options and restricted units become fully vested upon the disability, death or termination other than for cause of the holder or a change of control of our general partner. If the holder ceases to be an officer or employee of our general partner for any other reason, his unvested unit options or restricted units are forfeited. Unit option awards are less attractive than restricted units to the recipient because the fair value of the unit option at the grant date is generally less than the fair value of the restricted unit at the grant date, which bears no cost to the recipient. Furthermore, unit options, which vest in three years, are generally granted in hopeful anticipation of more immediate increases in unit prices, whereby restricted units that vest over a longer four-year period are granted more for unitholder ownership.

The size of the unit option and restricted unit grants is determined relative to our size and our market, employee qualifications and position, as well as master limited partnership peer group data. All grants to executive officers require board approval. Neither our general partner nor the compensation committee has a program, plan or practice to time options grants to its executives in coordination with the release of material nonpublic information. Any unit options grants made to non-executive employees typically will occur concurrently with grants to Named Executive Officers. All unit options are granted at the fair market value of our units on the date of grant. The compensation committee determines the aggregate amounts, terms and timing of unit option and restricted unit awards. The number of units covered by each award reflects the executive s level of responsibility along with past and anticipated future contributions to us. Initially, based on comparable options granted to executives of similar midstream and pipeline master limited partnerships at their initial public offerings, the CEO recommended to the chairman of the board the number of options to be granted to executive officers and key employees at our initial public offering in February 2005. In November 2005 the compensation committee approved 15,000 and 13,000 unit options to be granted to an additional Vice President of Operations and Engineering and a Vice President of Business Development, respectively for vacancies to be filled in early 2006. These unit amounts were determined based on a comparison of similar unit awards granted to companies within our marketplace.

Employment, Change in Control and Salary Continuation Agreements

No employment agreements exist with any employee of our general partner.

Change in control agreements exist only to the extent of all unexercised unit options and restricted units held by all employees of our general partner, which, in the event of any of the following become fully vested and exercisable. Change of control generally shall be deemed to occur upon the occurrence of one or more of the following events: (i) any sale, lease, exchange or other transfer or disposition of all or substantially all of the assets of the Partnership to any party not affiliated with the Partnership and/or any of our affiliates; (ii) the consolidation, reorganization, merger or other transaction pursuant to which more than 50% of the combined voting power of the outstanding equity interests in the Partnership cease to be directly or indirectly owned by our current majority owner group or their affiliate; or (iii) our general partner ceases to be the general partner of the Partnership.

Our general partner currently has no salary continuation agreement, or agreement having similar effect, in place with any employee of our general partner other than the change in control agreements described above.

Hiland Holdings GP, LP Class B Common Units

In connection with our initial public offering on February 15, 2005, our general partner issued Class B member interests in our general partner to our CEO and CFO as compensation for services to be rendered exclusively for the benefit of our general partner. In addition, in connection with the initial public offering of Hiland Holdings GP, LP on September 25, 2006, Class B common units in Hiland Holdings, GP, LP, who, at that time, became a majority common unitholder of Hiland Partners, LP, were issued to our CEO and CFO as consideration for their unvested Class B member interests in our general partner. The Hiland Holdings GP, LP Class B common units have substantially identical rights as Hiland Holdings GP, LP common units and, upon vesting, become convertible at the election of the holder into common units. Prior to conversion, the Class B common units are non-transferable. The Class B common units vest in equal increments on February 15, 2007 and February 15, 2008. In addition, any unvested Class B common units will become fully vested upon the disability, death or termination other than for cause of the holder or a change of control of our general partner. If either holder ceases to be an officer or employee of our general partner for any other reason, his unvested Class B common units will be forfeited and transferred to the Hiland Holdings GP, LP s contributing parties on a pro rata basis based on their vested ownership of Hiland Partners GP, LLC immediately prior to the contribution of those interests in connection with their formation. See Retention Agreement with Randy Moeder .

Summary Compensation Table

The following table sets forth information regarding compensation earned by our CEO, our CFO and three other most highly compensated executive officers employed in 2006:

SUMMARY COMPENSATION TABLE

		Annual Compensation		Long-Term Compensation			
Name and Principal Position	**Year**	**Salary ($)(1)**	**Bonus ($)(2)**	**Unit Awards ($)(3)**	**Option Awards ($)(4)**	**All Other Compensation ($)**	**Total ($)**
Randy Moeder President and Chief Executive Officer	2006	$ 231,058	$ 85,000	$	$ 52,534	$ 10,855	$ 379,447
Ken Maples Vice President Finance, Secretary and Chief Financial Officer	2006	$ 192,490	$ 55,000	$	$ 32,834	$ 9,560	$ 289,884
Robert Shain Vice President of Operations and Engineering	2006	$ 126,151	$ 40,000	$ 4,071	$ 27,858	$ 69,950	$ 268,030
Ron Hill Vice President of Business Development	2006	$ 147,692	$	$	$ 37,624	$ 3,173	$ 188,489
Clint Duty Former Vice President of Operations and Engineering	2006	$ 46,577	$	$	$ 12,325	$ 2,598	$ 61,500

(1) Salary includes base salary and payment in respect of accrued vacation, holidays and sick days. Mr. Duty left our employment on April 14, 2006.

(2) Bonuses for Mr. Moeder and Mr. Maples were awarded in March 2006. Mr. Shain was awarded a sign on bonus of $40,000 on March 20, 2006, his date of hire.

(3) At the November 10, 2006 compensation committee meeting, Mr. Shain was awarded 3,000 restricted units at $48.85 per unit, the closing price that day. The restricted units vest in quarterly increments on the anniversary of the grant date over a period of four years. Periodic distributions on the restricted units are held in trust by our general partner until the units vest.

(4) Mr. Moeder, Mr. Maples and Mr. Duty were granted 32,000, 20,000 and 20,000 unit options, respectively, at an exercise price of $22.50 per unit on February 10, 2005. The grant date fair value of $5.11 per unit was determined in accordance with FAS 123R using the American Binomial option-pricing model. Mr. Duty forfeited his remaining unvested 13,333 unit options when he left our employment. Mr. Hill was hired on January 5, 2006 and was awarded 13,000 unit options at a per unit exercise price of $38.72 with a grant date fair value of $4.82 per unit. On March 20, 2006, Mr. Shain was awarded 15,000 unit options at a per unit exercise price of $40.70 with a grant date fair value of $3.91 per unit. The exercise price of the options granted equaled the market price of the units on the grant date. The fair value of each option granted, as determined in accordance with FAS 123R, was estimated on the date of grant using the American Binomial option-pricing model. All unit options vest over a three-year period beginning on their respective date of grant.

All other compensation includes our discretionary contributions to our defined contribution retirement plan under which we make contributions to the plan based on a percentage of eligible employees compensation. Additionally, we paid relocation expenses of $68,104 for Mr. Shain.

Grants of Plan Based Awards

The following table provides information regarding unit options and restricted units awarded in 2006:

GRANTS OF PLAN BASED AWARDS

Name	**Grant Date**	**All Other Unit Awards: Number of Units (#)**	**Base Price of Unit Awards ($/Unit)**	**All Other Option Awards: Number of Securities Underlying Options (#)**	**Exercise or Base Price of Option Awards ($/Unit)**	**Grant Date Fair Value of Option Awards ($/Unit)**
Mr. Shain	3/20/2006			15,000	$ 40.70	$ 3.91
	11/10/2006	3,000	$ 48.85			
Mr. Hill	1/5/2006			13,000	$ 38.72	$ 4.82

Mr. Shain and Mr. Hill were awarded the unit options on each of their respective hire dates. Mr. Shain was awarded 3,000 restricted units in November 2006.

Outstanding Equity Awards at Fiscal Year-End Table

The following table provides information regarding outstanding awards that have been granted, but the ultimate outcomes of which have not been realized:

GRANTS OF PLAN BASED AWARDS

Name	Grant Date	All Other Unit Awards: Number of Units (#)	Base Price of Unit Awards ($/Unit)	All Other Option Awards: Number of Securities Underlying Options (#)	Exercise or Base Price of Option Awards ($/Unit)	Grant Date Fair Value of Option Awards ($/Unit)
Mr. Shain	3/20/2006			15,000	$ 40.70	$ 3.91
	11/10/2006	3,000	$ 48.85			
Mr. Hill	1/5/2006			13,000	$ 38.72	$ 4.82

(1) One half, or 10,667 of Mr. Moeder s unit options vested on February 10, 2007. The remainder vest on February 10, 2008.

(2) One half, or 6,667 of Mr. Maples unit options vested on February 10, 2007. The remainder vest on February 10, 2008.

(3) Mr. Shain s options vest in one-third annual increments beginning on March 20, 2007. Mr. Shain s restricted units vest in annual increments over a period of four years beginning on November 10, 2007. The market value of Mr. Shain s restricted units that have not vested was based on the closing price of $54.70 per unit on December 29, 2006.

(4) One third, or 4,333 of Mr. Hill s options vested on January 5, 2007. The remainder vest equally on January 5, 2008 and January 5, 2009.

On April 14, 2006, Mr. Duty left our employment and forfeited 13,333 unvested unit options issued to him on February 10, 2005.

Option Exercises and Units Vested Table

The table presented below provides information of the values realized upon the exercise of options during 2006 based on the difference between the market price of the underlying units at exercise and the exercise or base price of the unit options:

OPTION EXERCISES AND UNITS VESTED

Name	Option Awards Number of Units Acquired on Exercise (#)	Value Realized Upon Exercise ($)
Mr. Moeder	10,667	$ 172,485
Mr. Maples	6,667	$ 110,006
Mr. Duty	6,667	$ 112,472

No restricted units granted to executive officers vested in 2006.

Director Compensation

Mr. Harold Hamm, the chairman of the board of directors of our general partner and a non-employee director, receives no form of director compensation whatsoever. Similarly, our CEO, Mr. Moeder and our CFO, Mr. Maples, who are employees of our general partner, are also non-compensated members of the board of directors of our general partner. The table below shows the total compensation paid in 2006 to each of our current non-employee directors

DIRECTOR COMPENSATION

Name	Annual Base Fee(1) ($)	Committee Fees ($)	Restricted Unit Awards(2) ($)	Restricted Unit Distributions(3) ($)	Total ($)
Michael L. Greenwood	$ 31,000	$ 17,500	$ 44,450	$ 1,231	$ 94,181
Edward D. Doherty	$ 31,000	$ 12,500	$ 44,450	$ 1,231	$ 89,181
Rayford T. Reid	$ 31,000	$ 3,000	$ 44,450	$ 1,231	$ 79,681
Shelby E. Odell	$ 31,000	$ 8,000	$ 46,570	$ 1,231	$ 86,801
John T. McNabb, II(4)	$ 28,000	$ 4,500	$ 88,000	$	$ 120,500
Dr. David L. Boren(4)	$ 28,000	$ 1,000	$ 88,000	$	$ 117,000

(1) Includes an annual base fee of $25,000 per director plus $1,500 per director for each quarterly board of directors meeting attended.

(2) The value shown is the number of restricted unit granted in 2006 times the closing price of our units on the day of grant. The value given does not reflect a reduction for the fact that the shares are subject to potential forfeiture in the event the director leaves the board before the four-year vesting period. Three non-employee directors each received 1,000 restricted units on their first anniversary date and two other non-employee directors received 2,000 restricted units each on August 11, 2006, the date they were first elected the board.

(3) Represents the aggregate cash distributions paid at the time the units vested on all restricted units held by the director during 2006.

(4) Mr. McNabb and Dr. Boren were elected to the board on August 11, 2006.

No additional remuneration is paid to officers of our general partner who also serve as directors. Our independent directors 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 receive an annual retainer of $2,500. In addition, each independent 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 for his actions associated with being a director to the fullest extent permitted under Delaware law.

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. CRI 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, CRI agreed to continue to provide these services to us for two years after our initial public offering, at the lower of CRI s cost to provide the services or $50,000 per year. During the third quarter of 2006, we hired a director of information technology and a director of human resources and transitioned these services away from CRI. The remainder of general and administration services provided by CRI under this agreement expired on February 15, 2007.

Long-Term Incentive Plan

Our general partner has adopted the Hiland Partners Long-Term Incentive Plan for employees and directors of our general partner and employees of its affiliates. The plan is intended to promote our interests and the interests of our general partner by providing to employees and directors of our general partner and its affiliates incentive compensation awards for superior performance that are based on units. The plan is also contemplated to enhance the ability of our general partner, its affiliates or us to attract and retain the services of individuals who are essential for our growth and profitability and to encourage them to devote their best efforts to advancing our business. 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 of our 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 January 1, 2007, we have outstanding unit options to employees, officers and directors of our general partner to purchase an aggregate of 128,468 common units with a weighted average exercise price of $28.24. Please see the option grant table above for a description of grants made to named executive officers during 2006 and 2005. 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. .

In February 2006, one third of the 143,000 unit options granted on February 10, 2005 vested. Of the 47,666 that vested, 39,633 were exercised in February 2006, resulting in cash contributions to us of $0.9

million. Additionally, 41,000 of the unit options granted on February 10, 2005 vested on February 10, 2007 and 4,333 of the unit options granted in 2006 vested on January 5, 2007. Of the total 45,333 that vested, 39,930 were exercised in February 2007, resulting in cash contributions to us of $1.0 million.

Retention Agreement with Randy Moeder

In connection with Randy Moeder s resignation, Mr. Moeder, the general partner of Hiland Partners, LP, the general partner of Hiland Holdings GP, LP and certain other parties entered into a Retention Agreement. Under the agreement, if Mr. Moeder continues his employment until the earlier to occur of September 1 2007, the date Mr. Moeder s employment is terminated for any reason and a mutually agreeable date, a portion of his 10,666 unvested options to purchase common units of Hiland Partners, LP and a portion of his 72,249 unvested Class B Units in Hiland Holdings GP, LP will vest upon his termination of employment. The portion of his unvested options and Class B Units that will vest will be equal to the number of days in the period beginning on February 10, 2007, in the case of the options, and February 15, 2007, in the case of the Class B Units, and ending on the date on which his employment is terminated. Mr. Moeder will forfeit the right to receive any remaining unvested options and Class B Units on such date.

Report of the Compensation Committee

The compensation committee of the Board of Directors of Hiland Partners GP, LLC administers the executive compensation program of Hiland Partners, LP. The compensation committee is primarily responsible for reviewing, approving and reporting to the Board of Directors of Hiland Partners GP, LLC on major compensation and benefits plans, policies and programs of Hiland Partners, LP; reviewing and evaluating the performance and approving the compensation of senior executive officers; and overseeing management development programs, performance assessment of senior executives and succession planning. Other specific duties and responsibilities include: annually reviewing and approving corporate goals and objectives relevant to the CEO base compensation, incentive-compensation plans and equity-based plans; evaluating the CEO s performance in light of those goals and objectives, and recommending to the Board of Directors, either as a committee or together with the other independent directors, the CEO s compensation levels based on this evaluation; and producing the required annual report on executive compensation. The compensation committee annually evaluates the effectiveness of the executive compensation program in meeting its objectives.

As required by applicable regulations of the Securities and Exchange Commission, the compensation committee reviewed and discussed with management the compensation discussion and analysis contained in this Annual Report on Form 10-K. Based on the reviews and discussions referred to above, the compensation committee recommended to the Board of Directors of Hiland Partners GP, LLC that the compensation discussion and analysis be included in the Annual Report on Form 10-K for the year ended December 31, 2006 for filing with the SEC.

Respectively submitted on March 13, 2007 by the members of the compensation committee of the Board of Directors of Hiland Partners GP, LLC:

Harold Hamm, Chairman
John T. McNabb, II
Rayford T. Reid
Edward D. Doherty*
Michael L. Greenwood*

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* From May 2005 to August 2006, Edward D. Doherty was Chairman of the committee and Michael L. Greenwood was a member of the committee.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters

Beneficial Ownership Of Hiland Partners, LP. The following table sets forth the beneficial ownership of our units as of March 5, 2007 held by each person who beneficially owned more than 5% or more of the then outstanding units and all of the directors, named executive officers, and directors and executive officers as a group of our general partner.

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)(3)	1,301,471	24.9 %	4,080,000	100.0 %	57.8 %
Randy Moeder(1)(2)	10,667				
Ken Maples(1)(2)(4)	6,667				
Robert Shain(1)(5)	8,000	*			*
Ron Hill(1)					
Clint Duty(1)(8)					
Michael L. Greenwood(1)(2)(6)	11,291	*			*
Edward D. Doherty(1)(2)(6)	3,000	*			*
Rayford T. Reid(1)(2)(6)	15,818	*			*
Shelby E. Odell(1)(2)(6)	3,000	*			*
John T. McNabb, II(1)(7)	2,000	*			*
Dr. David L. Boren(1)(7)	2,000	*			*
Kayne Anderson Capital Advisors, L.P.(9)	377,292	7.2 %			4.1 %
Fiduciary Asset Management, LLC.(10)	384,980	7.4 %			4.1 %
All directors and executive officers as a group	1,363,914	26.1 %	4,080,000	100.0 %	58.5 %

* Less than 1%.

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

(2) These individuals each hold an ownership interest in Hiland Holdings GP, LP as indicated in the following table.

(3) Mr. Hamm indirectly owns 94% of Hiland Partners GP Holdings, LLC, the general partner of Hiland Holdings GP, LP. Accordingly, Mr. Hamm is deemed to be the beneficial owner of the 1,301,471 common units and 4,080,000 subordinated units held by Hiland Holdings GP, LP.

(4) These units underly unit options and are deemed to be outstanding pursuant to Rule 13d-3.

(5) 3,000 of the indicated common units are restricted units that vest on the anniversary of the grant date over a period of four years and 5,000 of these units underly unit options and are deemed to be outstanding pursuant to Rule 13d-3.

(6) 1,500 of the indicated common units are restricted units that vest on the anniversary of the grant date over a period of three years and 1,000 of the indicated common units are restricted units that vest on the anniversary of the grant date over a period of four years.

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

(8) The address of this person is 13779 E. 51st Street, Apt 3206, Tulsa, Oklahoma 74134.

(9) The address of this person is 1800 Avenue of the Stars, Second Floor, Los Angeles, CA 90067.

(10) The address of this person is 8112 Maryland Avenue, Suite 400, St. Louis, MO 63105.

Beneficial Ownership of Hiland Holdings GP, LP. The following table sets forth the beneficial ownership of units of Hiland Holdings GP, LP as of March 5, 2007 held by each person who beneficially owned more than 5% or more of the then outstanding units and all of the directors, named executive officers, and directors and executive officers as a group of Hiland Holdings GP, LP.

Name of Beneficial Owner(1)	**Common Units Beneficially Owned**	**Percentage of Common Units Beneficially Owned**
Harold Hamm(2)	7,657,870	35.4 %
Harold Hamm DST Trust(2)	3,205,120	14.8 %
Harold Hamm HJ Trust(2)	2,136,533	9.9 %
Randy Moeder(3)	388,890	1.8 %
Ken Maples(4)	161,587	*
Michael L. Greenwood(5)	2,000	*
Edward D. Doherty(5)	2,500	*
Rayford T. Reid(5)	27,000	*
Shelby E. Odell(5)	7,000	*
Dr. Cheryl L. Evans(5)	2,500	*
Dr. Bobby B. Lyle(5)	27,000	*
All directors and executive officers as a group	8,276,347	38.3 %

* Less than 1%.

(1) The address of each person listed above is 205 West Maple, Suite 1100, Enid, Oklahoma 73701, except for the Harold Hamm DST Trust and the Harold Hamm HJ Trust, which Mr. Bert Mackie is the trustee for both trusts and his address is c/o Security National Bank, 201 West Broadway, Enid, Oklahoma 73702-1272.

(2) Harold Hamm, the Harold Hamm DST Trust and the Harold Hamm HJ Trust have a 90.7%, 5.6% and a 3.7% ownership interest, respectively, in Continental Gas Holdings, Inc., which beneficially owns 8,443,076 common 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) These reported numbers include 144,498 Class B common units, of which 72,249 Class B common units are unvested. On February 19, 2007, Mr. Moeder elected to convert the 72,249 vested Class B units to common units. See Retention Agreement with Randy Moeder .

(4) These reported numbers include 87,552 Class B common units, of which 43,766 Class B common units are unvested.

(5) 2,000 of the indicated common units are restricted units that vest on the anniversary of the grant date over a period of four years.

The Class B common units were issued to Messrs. Moeder and Maples as consideration for their unvested ownership interests in Hiland Partners GP, LLC. The Class B common units will have substantially identical rights as the common units and, upon vesting, will become convertible at the election of the holder into common units. Prior to conversion, Messrs. Moeder and Maples will not be entitled to transfer the Class B common units. The Class B common units will vest in equal increments on February 15, 2008. In addition, any unvested Class B common units will become fully vested upon the disability, death or termination other than for cause of the holder or a change of control of our general partner. If either Mr. Moeder or Mr. Maples ceases to be an officer or employee of our general partner for

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any other reason, his unvested Class B common units will be forfeited and transferred to the Contributing Parties on a pro rata basis based on their vested ownership of Hiland Partners GP, LLC immediately prior to the contribution of those interests to us in connection with our formation. See Retention Agreement with Randy Moeder .

Beneficial Ownership of Our General Partner Interest. Hiland Holdings GP, LP owns all of our 2% general partner interest, all of our incentive distributions rights, 1,301,471 of our common units and 4,080,000 of our subordinated units.

Item 13. Certain Relationships and Related Transactions

Harold Hamm, the Harold Hamm DST Trust and the Harold Hamm HJ Trust own 60.1% of Hiland Holdings GP, LP, who owns all of our 2% general partner interest, all of our incentive distributions rights, 1,301,471 of our common units and 4,080,000 of our subordinated units.

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, CRI agreed to continue to provide certain general and administrative services to us for two years after our initial public offering, at the lower of CRI s cost to provide the services or $50,000 per year. During the third quarter of 2006, we hired a director of information technology and a director of human resources and transitioned these services away from CRI. The remainder of general and administration services provided by CRI under this agreement expired on February 15, 2007. 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.

Compensation Committee Interlocks and Insider Participation

Harold Hamm serves as the chairman of our Compensation Committee. Mr. Hamm controls CRI, and the required disclosure concerning related party transactions involving Mr. Hamm, CRI and us are set forth below.

Omnibus Agreement

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

- Harold Hamm s agreement not to compete and to cause his affiliates (including CRI) not to compete with us under certain circumstances;

- an indemnity by CRI, Hiland Partners, LLC and Continental Gas Holdings, Inc. for prior tax liabilities resulting from the assets contributed to the partnership;

- an indemnity by CRI for liabilities associated with oil and gas properties conveyed by CGI to CRI by dividend; and

- our two-year exclusive option to purchase the Bakken gathering system owned by Hiland Partners, LLC.

- for a two-year period, CRI will provide certain general and administrative services;

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

CRI, 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, CRI 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 CGI to CRI by dividend.

Option to Purchase the Bakken Gathering System

The omnibus agreement also contained 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

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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. received 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.

Services

CRI agreed to provide technology support and human resource functions to us for two years, at the lower of CRI s cost to provide the services or $50,000 per year. During the third quarter of 2006, we hired a director of information technology and a director of human resources and transitioned these services away from CRI.

Contracts with CRI

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 CRI. Hiland Partners, LLC received $3.9 million and $3.3 million for the years ended December 31, 2004 and 2003, respectively under this arrangement. In connection with our initial public offering, we entered into a four-year compression services agreement with CRI as described under Management s Discussion and Analysis of Financial Condition and Results of Operations Our Contracts Compression Services Agreement. For the years ended December 31, 2006 and 2005, we received revenues of $4.8 million and $4.2 million, respectively from CRI under this arrangement.

Gas Purchase Contracts

We purchase natural gas and NGLs from CRI and its affiliates. We purchased natural gas and NGLs from CRI and its affiliates in the amount of approximately $50.3 million, $45.8 million and $27.6 million for the years ended December 31, 2006, 2005 and 2004, respectively.

Badlands Purchase Contract

On November 8, 2005, we entered into a new 15-year definitive gas purchase agreement with CRI under which we will gather, treat and process additional natural gas, which is produced as a by-product of CRI s 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 are in the process of expanding 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, which is expected to be operational in the second quarter of 2007, and the expansion of our existing Badlands field-gathering infrastructure. We intend to invest approximately $40.0 million in the expansion project by the first quarter of 2007, of which approximately $31.7 million had been invested as of December 31, 2006. We expect to invest an additional $9.5 million on this project later 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 $219,000 and $257,000 during the years ended December 31, 2006 and 2005, respectively. We have continued to obtain services from these companies following the 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 amounts which would be charged by an unaffiliated third party.

In addition, 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 $11,000 and $65,000 during the years ended December 31, 2005 and 2004, respectively. Following completion of our initial public offering, this service arrangement was terminated.

We lease office space under operating leases from an entity wholly owned by Harold Hamm. Rents paid under these leases totaled approximately $118,000, $51,000 and $47,000 for the years ended December 31, 2006, 2005 and 2004 respectively. These rates are consistent with the rates charged to other non-affiliated tenants in the building which we office.

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

Item 14. Principal Accountant Fees and Services

Our audit committee has adopted an audit committee charter, which is available on our Web site at www.hilandpartners.com. The charter requires our audit committee to approve in advance all audit and non-audit services to be provided by our independent registered public accounting firm. Our audit committee ratified Grant Thornton LLP, Independent Registered Public Accounting Firm, to audit the books, records and accounts of Hiland Partners, LP for the year ended December 31, 2006. Audit fees paid to Grant Thornton LLP in 2006 include payments for our annual audit, review of documents filed with the Securities and Exchange Commission, Sarbanes Oxley Section 404 attest services and review of our quarterly reports on Form 10-Q. Fees for audit related services relate to consultation regarding an acquisition and internal control review. Tax fees include tax compliance, tax planning and acquisition matters. Fees paid in 2005 to Grant Thornton LLP for audit services included fees associated with the annual audit, regulatory filings required in our initial and secondary public offerings, preparation for Sarbanes-Oxley Section 404 attest services and reviews of our quarterly reports on Form 10-Q. Additional fees paid to Grant Thornton LLP for audit-related services consisted of consultation regarding an acquisition and for tax, which consisted of compliance and advisory services. Fees paid to Grant Thornton LLP for the periods indicated are as follows:

	2006	**2005**
Audit Fees	$ 338,000	$ 328,000
Audit Related Fees	8,000	1,000
Tax Fees	165,000	173,000
All Other Fees		
Total	$ 511,000	$ 502,000

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements

The financial statements listed in the accompanying Index to Consolidated Financial Statements are filed as part of this Annual Report on Form 10-K.

(b) Other Information

None.

EXHIBITS

Exhibit **Number**	**Description**
2.1	Acquisition Agreement by and among Hiland Operating, LLC and Hiland Partners, LLC dated as of September 1, 2005 (incorporated by referenced to Exhibit 2.1 of Registrant s Form 8-K filed September 29, 2005)
3.1	Certificate of Limited Partnership of Hiland Partners, LP. (incorporated by reference to Exhibit 3.1 of Registrant s Registration Statement on Form S-1 (File No. 333-119908))
3.2	First Amended and Restated Limited Partnership Agreement of Hiland Partners, LP (incorporated by reference to exhibit 3.2 of Registrant s annual report on Form 10-K filed on March 30, 2005)
3.3	Certificate of Formation of Hiland Partners GP, LLC (incorporated by reference to Exhibit 3.3 of Registrant s Registration Statement on Form S-1 (File No. 333-119908))
3.4	Second Amended and Restated Limited Liability Company Agreement of Hiland Partners GP, LLC (incorporated by reference to exhibit 10.2 of Registrant s Form 8-K filed on September 29, 2006)
10.1	Credit Agreement dated as of February 15, 2005 among Hiland Operating, LLC and MidFirst Bank (incorporated by reference to exhibit 10.1 of Registrant s annual report on Form 10-K filed on March 30, 2005)
10.2*	Hiland Partners, LP Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 of Registrant s Registration Statement on Form S-1 (File No. 333-119908))
10.3	Compression Services Agreement, effective as of January 28, 2005, by and among Hiland Partners, LP and Continental Resources, Inc. (incorporated by reference to exhibit 10.3 of Registrant s annual report on Form 10-K filed on March 30, 2005)
10.4	Gas Purchase Contract between Continental Resources, Inc. and Continental Gas, Inc. (incorporated by reference to Exhibit 10.4 of Registrant s Registration Statement on Form S-1 (File No. 333-119908))
10.5	Gas Purchase Contract Chesapeake Energy Marketing, Inc. and Continental Gas, Inc. (incorporated by reference to Exhibit 10.5 of Registrant s Registration Statement on Form S-1 (File No. 333-119908))
10.6	Gas Purchase Contract between Magic Circle Energy Corporation and Magic Circle Gas (incorporated by reference to Exhibit 10.6 of Registrant s Registration Statement on Form S-1 (File No. 333-119908))

10.7	Gas Purchase Contract between Range Resources Corporation and Continental Gas, Inc. (incorporated by reference to Exhibit 10.7 of Registrant s Registration Statement on Form S-1 (File No. 333-119908))
10.8	Contribution, Conveyance and Assumption Agreement among Hiland Partners, LP, Hiland Operating, LLC, Hiland GP, LLC, Hiland LP, LLC, Continental Gas, Inc., Hiland Partners GP, LLC, Hiland Partners, LLC, Continental Gas Holdings, Inc., Hiland Energy Partners, LLC, Harold Hamm, Harold Hamm HJ Trust, Harold Hamm DST Trust, Equity Financial Services, Inc., Randy Moeder, and Ken Maples effective as of February 15, 2005 (incorporated by reference to exhibit 10.8 of Registrant s annual report on Form 10-K filed on March 30, 2005)
10.9*	Form of Unit Option Grant (incorporated by reference to Exhibit 10.9 of Registrant s Registration Statement on Form S-1 (File No. 333-119908))
10.10	Omnibus Agreement among Continental Resources, Inc., Hiland Partners, LLC, Harold Hamm, Hiland Partners GP, LLC, Continental Gas Holdings, Inc., and Hiland Partners, LP effective as of February 15, 2005 (incorporated by reference to exhibit 10.10 of Registrant s annual report on Form 10-K filed on March 30, 2005)
10.11*	Director s Compensation Summary (incorporated by reference to exhibit 10.11 of Registrant s annual report on Form 10-K filed on March 30, 2005)
10.12*	Form of Restricted Unit Grant Agreement (incorporated by reference to exhibit 10.1 of Registrant s Form 8-K filed on November 14, 2005)
10.13	First Amendment, dated as of September 26, 2005 to Credit Agreement dated as of February 15, 2005 among Hiland Operating, LLC and the lenders thereto (incorporated by reference to exhibit 10.1 of Registrant s Form 8-K filed on September 29, 2005)
10.14	Gas Purchase Agreement among Hiland Partners, LP and Continental Resources, Inc. dated November 8, 2005 (incorporated by reference to exhibit 10.1 of Registrant s form 8-K filed on November 10, 2005)
10.15	Unit Purchase Agreement dated May 1, 2006 by and between Hiland Partners, LP and Hiland Partners GP, LLC (incorporated by reference to exhibit 10.1 of Registrant s form 8-K filed on May 3, 2006)
10.16	Asset Purchase Agreement dated March 30, 2006 by and between Hiland Operating, LLC and Enogex Gas Gathering, L.L.C. (incorporated by reference to exhibit 10.2 of Registrant s form 8-K filed on May 3, 2006)
10.17	Second Amendment, dated as of June 8, 2006, to Credit Agreement dated as of February 15, 2005 among Hiland Operating, LLC and the lenders thereto (incorporated by reference to exhibit 10.1 of Registrant s form 8-K filed on June 13, 2006)
10.18	Non-Competition Agreement dated September 25, 2006 (2006 by and among Hiland Partners, LP, Hiland Holdings GP, LP and Hiland Partners GP Holdings, LLC (incorporated by reference to exhibit 10.1 of Registrant s form 8-K filed on September 29, 2006)
10.19	Retention Agreement, dated as of March 14, 2007, by and among Randy Moeder, Hiland Partners GP, LLC, Hiland Partners GP Holdings, LLC and the other parties listed on the signature page thereto (incorporated by reference to exhibit 10.1 of Registrant s form 8-K filed on March 15, 2007)
19.1	Code of Ethics for Chief Executive Officer and Senior Finance Officers (incorporated by reference to exhibit 19.1 of Registrant s annual report on Form 10-K filed on March 30, 2005)

21.1	List of Subsidiaries of Hiland Partners, LP (incorporated by reference to exhibit 21.1 of Registrant s annual report on Form 10-K filed on March 30, 2005)
23.1	Consent of Grant Thornton LLP
31.1	Certification of Chief Executive Officer under Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification of Chief Financial Officer under Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification of Chief Executive Officer under Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of Chief Financial Officer under Section 906 of the Sarbanes-Oxley Act of 2002

Portions of this exhibit have been omitted pursuant to a request for confidential treatment.

* Constitutes management contracts or compensatory plans or arrangements.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized in the city of Enid, Oklahoma, on the 16th day of March, 2007.

HILAND PARTNERS, LP
By: Hiland Partners GP, LLC, its general partner

By:	/s/ RANDY MOEDER
	Randy Moeder
	Chief Executive Officer, President and Director

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant in the capacities indicated on the 16th day of March, 2007.

Signature	Title
/s/ HAROLD HAMM Harold Hamm	Chairman of the Board
/s/ RANDY MOEDER Randy Moeder	Chief Executive Officer, President and Director
/s/ KEN MAPLES Ken Maples	Chief Financial Officer, Vice President Finance, Secretary and Director
/s/ MICHAEL L. GREENWOOD Michael L. Greenwood	Director
/s/ EDWARD D. DOHERTY Edward D. Doherty	Director
/s/ RAYFORD T. REID Rayford T. Reid	Director
/s/ SHELBY E. ODELL Shelby E. Odell	Director
/s/ JOHN T. MCNABB, II John T. McNabb, II	Director
/s/ DR. DAVID L. BOREN Dr. David L. Boren	Director

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Hiland Partners, LP Consolidated Financial Statements:

Management s Report on Internal Control Over Financial Reporting

The management of Hiland Partners, LP (the Partnership) is responsible for establishing and maintaining an adequate internal control over financial reporting. Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes in accordance with accounting principles generally accepted in the United States of America. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. With the participation of the Chief Executive Officer and the Chief Financial Officer, our management has assessed the effectiveness of the Partnership s internal control over financial reporting as of December 31, 2006. In making its assessment, management has utilized the criteria set forth by the Committee of Sponsoring Organizations (COSO) of the Treadway Commission in *Internal Control Integrated Framework.* Management concluded that, based on its assessment, the Partnership s internal control over financial reporting was effective as of December 31, 2006.

Hiland Partners, LP management s assessment of the effectiveness of the Partnership s internal control over financial reporting as of December 31, 2006 has been audited by Grant Thornton, LLP, an independent registered public accounting firm, as stated in their report included herein.

/s/ RANDY MOEDER
Chief Executive Officer
/s/ KEN MAPLES
Chief Financial Officer

Report of Independent Registered Public Accounting Firm

Board of Directors

Hiland Partners GP, LLC

We have audited management s assessment, included in the accompanying Management s Report on Internal Control Over Financial Reporting, that Hiland Partners, LP and subsidiaries (the Partnership) maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of the Partnership s internal control over financial reporting based on our audit.

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

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management s assessment that the Partnership maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on criteria established in *Internal Control Integrated Framework* issued by COSO. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on *Internal Control Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of the Partnership as of December 31, 2006 and 2005, and the related consolidated statements of operations, cash flows, and changes in owners equity and comprehensive income for each of the three years in the period ended December 31, 2006 and our report dated March 13, 2007 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP
Oklahoma City, Oklahoma
March 13, 2007

Report of Independent Registered Public Accounting Firm

Board of Directors
Hiland Partners GP, LLC

We have audited the accompanying consolidated balance sheets of Hiland Partners, LP and subsidiaries (the Partnership) as of December 31, 2006 and 2005, and the related consolidated statements of operations, cash flows, and changes in owner s equity and comprehensive income for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Partnership s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Hiland Partners, LP and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, the Partnership adopted Statement of Financial Accounting Standards No. 123 (revised 2004), *Share-Based Payment,* on a modified prospective basis as of January 1, 2006.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Partnership s internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 13, 2007 expressed an unqualified opinion on the effectiveness of the Partnership s internal control over financial reporting and on management s assessment thereof.

/s/ GRANT THORNTON LLP
Oklahoma City, Oklahoma
March 13, 2007

HILAND PARTNERS, LP

Consolidated Balance Sheets

	December 31, 2006	December 31, 2005
	(in thousands, except unit amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 10,386	$ 6,187
Accounts receivable:		
Trade	23,702	21,893
Affiliates	1,284	1,523
	24,986	23,416
Fair value of derivative assets	4,707	868
Other current assets	725	395
Total current assets	40,804	30,866
Property and equipment, net	252,801	120,715
Intangibles, net	46,561	41,179
Fair value of derivative assets	1,955	181
Other assets, net	1,695	1,028
Total assets	$ 343,816	$ 193,969
LIABILITIES AND OWNERS EQUITY		
Current liabilities:		
Accounts payable	$ 19,032	$ 13,324
Accounts payable affiliates	4,412	6,122
Fair value of derivative liabilities	1,902	
Accrued liabilities	1,173	1,126
Total current liabilities	26,519	20,572
Commitments and contingencies (Note 7)		
Long-term debt	147,064	33,784
Fair value of derivative liabilities	291	
Asset retirement obligation	2,196	1,024
Owners equity		
Limited partners interest:		
Common unitholders (5,166,413 and 4,350,000 units issued and outstanding at December 31, 2006 and December 31, 2005, respectively)	139,781	110,027
Subordinated unitholders (4,080,000 units issued and outstanding)	19,913	25,126
General partner interest	3,696	2,676
Unearned compensation		(289)
Accumulated other comprehensive income	4,356	1,049
Total owners equity	167,746	138,589
Total liabilities and owners equity	$ 343,816	$ 193,969

The accompanying notes are an integral part of these consolidated financial statements.

HILAND PARTNERS, LP

Consolidated Statements of Operations

	Year Ended December 31, 2006	2005	Predecessor Year Ended December 31, 2004
	(In thousands, except per unit amounts)		
Revenues:			
Midstream operations			
Third parties	$ 210,732	$ 157,138	$ 95,019
Affiliates	4,135	5,246	3,277
Compression services, affiliate	4,819	4,217	
Total revenues	219,686	166,601	98,296
Operating costs and expenses:			
Midstream purchases (exclusive of items shown separately below)	105,884	87,247	54,962
Midstream purchases affiliate (exclusive of items shown separately below)	50,309	45,842	27,570
Operations and maintenance	16,071	7,359	4,933
Depreciation, amortization and accretion	22,130	11,112	4,127
Gain on sale of assets			(19)
General and administrative expenses	4,994	2,470	1,082
Total operating costs and expenses	199,388	154,030	92,655
Operating income	20,298	12,571	5,641
Other income (expense):			
Interest and other income	323	192	40
Amortization of deferred loan costs	(407)	(484)	(102)
Interest expense	(5,532)	(1,942)	(702)
Other income (expense), net	(5,616)	(2,234)	(764)
Income from continuing operations	14,682	10,337	4,877
Discontinued operations, net			35
Net income	14,682	10,337	$ 4,912
Less income attributable to predecessor		493	
Less general partner interest in net income	2,409	464	
Limited partners interest in net income	$ 12,273	$ 9,380	
Net income per limited partners unit basic	$ 1.37	$ 1.33	
Net income per limited partners unit diluted	$ 1.36	$ 1.32	
Weighted average limited partners units outstanding basic	8,961	7,034	
Weighted average limited partners units outstanding diluted	9,010	7,086	

The accompanying notes are an integral part of these consolidated financial statements.

HILAND PARTNERS, LP

Consolidated Statements of Cash Flows
(in thousands, except unit amounts)

	Year Ended December 31, 2006	2005	Predecessor Year Ended December 31, 2004
Cash flows from operating activities:			
Net income	$ 14,682	$ 10,337	$ 4,912
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	22,064	11,083	4,170
Accretion of asset retirement obligation	66	8	23
Amortization of deferred loan cost	407	483	102
Gain on hedge ineffectiveness	(113)		
Unit based compensation	473	28	
Gain on sale of assets			(19)
(Increase) decrease in current assets, net of acquisition effects:			
Accounts receivable trade	(1,809)	(17,507)	(1,831)
Accounts receivable affiliates	239	(765)	(226)
Inventories		153	122
Other current assets	(330)	(213)	(113)
Increase (decrease) in current liabilities, net of acquisition effects:			
Accounts payable	5,708	782	319
Accounts payable affiliates	(1,710)	3,124	482
Accrued liabilities	47	609	16
Increase in other assets	(144)		
Net cash provided by operating activities	39,580	8,122	7,957
Cash flows from investing activities:			
Additions to property and equipment	(62,137)	(10,389)	(5,326)
Payments for Kinta Area assets acquired	(96,400)		
Acquisition of net assets of Hiland Partners, LLC, less cash received		(64,559)	
Proceeds from disposals of property and equipment	111	60	36
Net cash used in investing activities	(158,426)	(74,888)	(5,290)
Cash flows from financing activities:			
Proceeds from initial public offering net		48,128	
Redemption of common units from organizers		(6,278)	
Distributions to organizers		(3,851)	
Cash not contributed by organizers		(869)	
Payment of initial public offering costs		(2,249)	
Proceeds from long-term borrowings	113,280	99,000	500
Payments on long-term borrowings		(89,167)	(2,428)
Increase in deferred offering cost			(1,012)
Debt issuance costs	(930)	(1,332)	(6)
Proceeds from secondary public offering net		66,071	
Payment of secondary public offering costs		(607)	
Cash distribution to controlling member for net assets of Hiland Partners, LLC		(27,768)	
General partner contribution for issuance of restricted common units	12	7	
Common units issued to our general partner	35,000		
Proceeds from unit options exercise	1,312		
Cash distribution to unitholders	(25,629)	(8,349)	
Net cash provided by (used in) financing activities	123,045	72,736	(2,946)
Increase (decrease) for the year	4,199	5,970	(279)
Beginning of year	6,187	217	496
End of year	$ 10,386	$ 6,187	$ 217
Supplementary information			
Cash paid for interest, net of amounts capitalized	$ 4,514	$ 1,362	$ 787

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements of Cash Flows (continued):

Non cash investing and financing activities:	
Assumed asset retirement obligations of $1,106 on May 1, 2006 in connection with the acquisition of the Kinta Area gathering assets	
Fair value of net assets acquired from Hiland Partners, LLC on February 15, 2005 in exchange for 252,927 common units and 1,433,251 subordinated units.	
Accounts receivable and other current assets	$ 162
Property and equipment	31,600
Intangible assets	26,800
Other assets	105
Total assets acquired	58,667
Less accounts payable and other current liabilities assumed	(741)
Less current portion of long-term debt assumed	(8,879)
Less asset retirement obligation assumed	(398)
Fair value of net assets acquired	$ 48,649
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.	

The accompanying notes are an integral part of these consolidated financial statements.

HILAND PARTNERS, LP
Consolidated Statement of Changes in Owners Equity and Comprehensive Income
For the Years Ended December 31, 2006, 2005 and 2004

	Hiland Partners, LP							
	Predecessor Equity	Common Units	Subordinated Units	General Partner Interest	Unearned Compensation	Accumulated Other Comprehensive Income	Total	Total Comprehensive Income
	(in thousands, except unit amounts)							
Balance, January 1, 2004	$ 21,739	$	$	$	$	$	$ 21,739	
Net Income	4,912						4,912	$ 4,912
Transfer of discontinued operations to parent company	(2,141)						(2,141)	
Balance, December 31, 2004	24,510						24,510	
Assets not contributed to Hiland Partners, LP at initial public offering	(9,972)						(9,972)	
Net income from January 1, 2005 through February 14, 2005	493						493	493
Allocation of net parent investment to affiliated unitholders (467,073 common units and 2,646,749 subordinated uints)	(15,031)	2,191	12,418	422				
Contribution of certain net assets of Hiland Partners, LLC by owners (252,927 common units and 1,433,251 subordinated units)		7,092	40,190	1,367			48,649	
Proceeds from initial public offering, net of underwriter discount (2,300,000 common units)		48,128					48,128	
Offering costs of initial public offering		(3,365)					(3,365)	
Redemption of Common Units from Organizers (300,000 common units)		(6,278)					(6,278)	
Distributions to organizers		(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				7			7	
Proceeds from secondary public offering, net of underwriter discount (1,630,000 common units)		64,682		1,389			66,071	
Offering costs of secondary public offering		(607)					(607)	
Periodic cash distributions		(3,268)	(4,896)	(185)			(8,349)	
Issuance of restricted units (8,000 common units)		317			(317)			
Unit based compensation					28		28	
Change in fair value of derivatives						1,049	1,049	1,049
Net income from February 15, 2005 through December 31, 2005		4,004	5,376	464			9,844	9,844
Comprehensive Income								$ 11,386
Balance, December 31, 2005		110,027	25,126	2,676	(289)	1,049	138,589	
Elimination of unearned compensation upon adoption		(289)			289			

of SFAS 123(R)								
Issuance of 761,714 common units to our general partner		34,300		700			35,000	
Proceeds from 52,699 unit options exercise		1,286		26			1,312	
Issuance of 13,000 restricted common units				12			12	
Periodic cash distributions		(12,690)	(10,812)	(2,127)			(25,629)	
Unit based compensation		473					473	
Other comprehensive income reclassified to income on closed derivative transactions						(3,582)	(3,582)	$ (3,582)
Change in fair value of derivatives						6,889	6,889	6,889
Net income		6,674	5,599	2,409			14,682	14,682
Comprehensive income								$ 17,989
Balance, December 31, 2006	$	$ 139,781	$ 19,913	$ 3,696	$	$ 4,356	$ 167,746	

The accompanying notes are an integral part of this consolidated financial statement.

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HILAND PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2006 and 2005
(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 oper certain midstream natural gas plants, gathering systems and compression and water injection assets located in the states of Oklahoma, North Dakota, Wyoming, Texas and Mississippi that were previously owned by Continental Gas, Inc. (Predecessor or CGI) and Hiland Partners, LLC. We commenced operations on February 15, 2005, and concurrently with the completion of our initial public offering, CGI contributed a substantial portion of its net assets to us.

CGI constitutes our predecessor. The transfer of ownership of net assets from CGI to us 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 us. 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 our initial public offering, we have operated in midstream and compression services segments. On September 26, 2005, we 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. On May 1, 2006, we acquired the Kinta Area gathering assets from Enogex Gas Gathering, L.L.C., consisting of certain eastern Oklahoma gas gathering assets, for $96.4 million. We financed this acquisition with $61.2 million of borrowings from our credit facility and $35.0 million of proceeds from the issuance to Hiland Partners GP, LLC, our general partner, of 761,714 common units and 15,545 general partner equivalent units, both at $45.03 per unit.

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.

Principles of Consolidation

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

For financial reporting, we consider all highly liquid investments with maturity of three months or less at date 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 our 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.

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, financial derivatives, accounts payable and long-term 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. Derivative instruments are reported in the accompanying consolidated financial statements at fair value in accordance with Statement of Financial Accounting Standards (SFAS) No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended. Fair value of our derivative instruments is determined based on management estimates through utilization of market data including forecasted forward natural gas and NGL prices as a function of forward NYMEX natural gas and light crude prices. The fair value of long-term debt approximates its carrying value due to the variable interest rate feature of such debt.

Commodity Risk Management

We engage in price risk management activities in order to minimize the risk from market fluctuation in the price of natural gas. To qualify as a hedge, the price movements in the commodity derivatives must be highly correlated with the underlying hedged commodity. Gains and losses related to commodity derivatives which qualify as hedges are recognized in income when the underlying hedged physical transaction closes and are included in the consolidated statements of operations as revenues from midstream operations.

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. However, if a derivative does qualify for hedge accounting, depending on the nature of the hedge, changes in fair value can be offset against the change in fair value of the hedged item through earnings or recognized in other comprehensive income until such time as the hedged item is recognized in earnings. To qualify for cash flow hedge accounting, the cash flows from the hedging instrument must be highly effective in offsetting changes in cash flows due to changes in the underlying item being hedged. In addition, all hedging relationships must be designated, documented, and reassessed periodically. SFAS No. 133 also 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 to 24 month term.

Currently, our derivative financial instruments that qualify for hedge accounting are designated as cash flow hedges. The cash flow hedge instruments hedge the exposure of variability in expected future cash flows that is attributable to a particular risk. The effective portion of the gain or loss on these derivative instruments is recorded in accumulated other comprehensive income in partners equity and reclassified into earnings in the same period in which the hedged transaction closes. The asset or liability related to the derivative instruments is recorded on the balance sheet as fair value of derivative assets or liabilities. Any ineffective portion of the gain or loss is recognized in earnings immediately.

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 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.

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 their estimated lives of ten years. We review 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 based on the discounted probable cash flows of the intangible assets. No impairments of intangible assets were recorded during the years ended December 31, 2006, 2005 and 2004. On May 1, 2006 we acquired the Kinta Area gathering assets and recorded identifiable customer relationships of $10,492. Intangible assets consisted of the following for the periods indicated:

	As of December 31, 2006	As of December 31, 2005
Gas sales contracts	$ 25,585	$ 25,585
Compression contracts	18,515	$ 18,515
Customer relationships	10,492	
	54,592	44,100
Less accumulated amortization	8,031	2,921
Intangible assets, net	$ 46,561	$ 41,179

During the years ended December 31, 2006 and 2005 we recorded $5,110 and $2,921, respectively of amortization expense. We had no intangible assets prior to February 15, 2005. Estimated aggregate amortization expense for each of the five succeeding fiscal years is $5,459 from 2007 through 2011 and a total of $19,266 for all years thereafter.

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 assets 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.

No impairment charges were recognized during each of the years ended December 31, 2006, 2005 and 2004.

Other Assets

Unamortized deferred loan costs related to the long-term debt on our bank credit facility totaling $1,550 and $1,028 as of December 31, 2006 and 2005, respectively, are included in other noncurrent assets. The deferred loan costs are amortized using the straight-line method over the term of the debt for the bank credit facility.

Revenue Recognition

Revenues for sales and gathering of natural gas and NGLs are recognized at the time all gathering and processing activities are completed, the product is delivered and title, if applicable, is transferred. Revenues from oil and gas production (discontinued operations) are recorded in the month produced and title is transferred to the purchaser. Revenues related to our compression segment are recognized as monthly services are rendered under a four-year fixed-fee contract that we entered into concurrently with our initial public offering.

Comprehensive Income

Comprehensive income includes net income and other comprehensive income, which includes, but is not limited to, changes in the fair value of derivative financial instruments. Pursuant to SFAS No. 133, for derivatives qualifying as hedges, the effective portion of changes in fair value are recognized in owners equity as accumulated other comprehensive income and reclassified to earnings when the underlying hedged physical transaction closes.

Net Income per Limited Partners Unit

Net income per limited partners unit is computed based on the weighted-average number of common and subordinated units outstanding during the period. The computation of diluted net income per limited partner unit further assumes the dilutive effect of unit options and restricted units. Net income per limited partners unit is computed by dividing net income applicable to limited partners, after deducting the general partner s 2% interest and incentive distributions, and, for 2005, after deducting net income attributable to the Predecessor (before February 15, 2005), by both the basic and diluted weighted-average number of limited partnership units outstanding.

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. Therefore, there is no provision for income taxes included in our consolidated financial statements. Taxable income, gain, loss and deductions are allocated to the unitholders who are responsible for payment of any income taxes thereon.

Net income for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under the partnership agreement. Individual unitholders have different investment bases depending upon the timing and price of acquisition of their partnership units. Furthermore, each unitholder s tax accounting, which is partially dependent upon the unitholder s tax position, differs from the accounting followed in the consolidated financial statements. Accordingly, the aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined because information regarding each unitholder s tax attributes in our partnership is not available to us.

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, 2006 we had imbalance receivables of $1,028 and no imbalance payables. As of December 31, 2005, we had no imbalance receivables or payables.

Share-Based Compensation

Our general partner, Hiland Partners GP, LLC adopted the Hiland Partners, LP Long-Term Incentive Plan for its employees and directors of our general partner and employees of 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. Under the unit option grant agreement, granted options of common units will vest and become exercisable in one-third increments on the anniversary of the grant date over three years. Vested options are exercisable within the option s contractual life of ten years after the grant date.

In October 1995 the FASB issued SFAS No. 123, Share-Based Payment, which was revised in December 2004 (SFAS 123R). SFAS 123R requires that the compensation cost relating to share-based payment transactions be recognized in the financial statements and that cost be measured based on the fair value of the equity or liability instruments issued. We adopted SFAS 123R as of January 1, 2006 and applied SFAS 123R using the permitted modified prospective method beginning as of the same date and our unearned deferred compensation of $289 as of January 1, 2006 has been eliminated against common unit equity. Prior to January 1, 2006 we recorded any unamortized compensation related to restricted unit awards as unearned compensation in equity. We expect no change to our cash flow presentation from the adoption of SFAS 123R since no tax benefits are recognized by us as a pass through entity. Our compensation expense for these awards is recognized on the graded vesting attribution method. Units to be issued under our unit incentive plan may be from newly issued units. No compensation expense was recognized in 2005 for our unit options granted during 2005. Prior to our adoption of SFAS 123R on January 1, 2006, we applied Accounting Principles Board Opinion No. 25 and related interpretations in accounting for our unit-based compensation awards. The following pro forma data was calculated as if compensation cost for our unit-based compensation awards during the year ended December 31, 2005 was determined based upon the fair value at the grant date consistent with the methodology prescribed under SFAS No. 123.

	Year Ended December 31, 2005
Net income as reported	$ 10,337
Share based compensation adjustment	(419)
Pro forma net income	9,918
Less income attributable to predecessor	(493)
Less general partner interest	(447)
Limited partner s interest in pro forma net income	$ 8,978
Net income per limited partner unit as reported basic	$ 1.33
Net income per limited partner unit as reported diluted	$ 1.32
Adjustment basic	$ (0.05)
Adjustment diluted	$ (0.05)
Proforma net income per limited partner unit basic	$ 1.28
Proforma net income per limited partner unit diluted	$ 1.27
Weighted average limited partner units outstanding basic	7,034,000
Weighted average limited partner units outstanding diluted	7,086,000

The fair value of each option granted was estimated on the date of grant using the American Binomial option-pricing model that used the assumptions noted below. Expected and weighted-average volatility is based on our peer group volatility averages as determined on the option grant dates. Expected volatility of options granted ranged from 16% to 31% and weighted-average volatility ranged from 18% to 30%. For options granted in 2006 and 2005, expected lives of 6.0 years are calculated by the simplified method as prescribed under SEC Staff Accounting Bulletin 107 and represent the period of time that unit options granted are expected to be outstanding. The risk-free interest rate for periods within the contractual life of the option is based on the U.S. Treasury yield in effect at the time of grant. The exercise price of the options granted equaled the market price of the units on the grant date.

	Year Ended December 31, 2006	**Year Ended December 31, 2005**
Expected volatility	16.1% - 20.2 %	20.2% - 31.0 %
Weighted-average volatility	18.0 %	29.4 %
Expected dividend yield	6.4 %	5.2 %
Risk-free interest rate	4.5 %	4.5 %

The following table summarizes information about outstanding options for the year ended December 31, 2006.

Options	Units	Weighted Average Exercise Price ($)	Weighted-Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value ($)
Outstanding at January 1, 2006	167,500	$ 24.70		
Granted	28,000	$ 39.78		
Exercised	(52,699)	$ 24.40		$ 876
Forfeited or expired	(14,333)	$ 23.53		
Outstanding at December 31, 2006	128,468	$ 28.24	8.4	$ 2,355
Exercisable at December 31, 2006	2,801	$ 28.79	8.1	$ 50

The weighted average grant date fair value of the 55,500 unit options vested during the year ended December 31, 2006 was $5.15 per unit. The weighted average grant date fair value of the 28,000 unit options granted during the year ended December 31, 2006 was $4.33 per unit. The weighted average grant date fair value of 167,500 unit options granted during the year ended December 31, 2005 was $5.30 per unit. As of December 31, 2006, there was $214 of total unrecognized compensation cost related to unvested unit based option awards granted under our Plan. This cost is expected to be recognized over a weighted-average period of 1.2 years.

On April 14, 2006, 13,333 of the unit options issued on February 10, 2005, were forfeited. We assumed no forfeitures in our fair value calculations, as we believe this forfeiture is an isolated incident and is not indicative of the future. Compensation expense for the year ended December 31, 2006 has been reduced by $21 as a result of the forfeiture.

As a result of adopting SFAS 123R on the modified prospective basis beginning on January 1, 2006, we expensed $354 related to unit options that were awarded in both 2006 and 2005. We recognized no unit option compensation expense in 2005. Basic and diluted earnings per unit were each reduced by $0.04 for the year ended December 31, 2006 as a result of the additional compensation recognized under SFAS 123R.

The following table summarizes information about restricted units for the year ended December 31, 2006.

Restricted Units	Units	Weighted Average Fair Value At Grant Date ($)
Non-vested at January 1, 2006	8,000	$ 39.69
Granted	13,000	$ 46.17
Vested	(2,000)	$ 39.69
Forfeited		
Non-vested at December 31, 2006	19,000	$ 44.12

During 2006, we issued (i) 1,000 units each to four non-employee board members of our general partner on their one-year anniversary dates, (ii) 2,000 units each on August 11, 2006 to two newly elected non-employee board members of our general partner, (iii) 3,000 units to an executive officer of our general partner and (iv) 2,000 units to certain employees of our general partner. Our general partner contributed $12 to us to maintain its 2% ownership interest.

Also during 2006, one fourth, or 2,000, of the 8,000 restricted units we issued to non-employee board members of our general partner in 2005 vested and were converted to common units. The weighted average grant date fair value of the restricted units issued in 2005 was $39.69 per unit.

A restricted unit is a common unit that is subject to forfeiture. The restricted units vest over a four-year period from the date of issuance. Periodic distributions on the restricted units are held in trust by our general partner until the units vest. Upon vesting, the grantee receives a common unit that is not subject to forfeiture. Each non-employee board member of our general partner is entitled to receive an additional 1,000 restricted common units on each anniversary date of the initial award.

Total compensation expense related to restricted units was $119 and $28 for the years ended December 31, 2006 and 2005, respectively. As of December 31, 2006, there was $770 of total unrecognized cost related to unvested restricted units. This cost is to be recognized over a weighted average period of 3.3 years.

Accounting for Asset Retirement Obligations

In accordance with SFAS No. 143, Accounting for Asset Retirement Obligations, we have recorded the fair value of liabilities for asset retirement obligations in the periods in which they are incurred and corresponding increases in the carrying amounts of the related long-lived assets. The asset retirement costs are subsequently allocated to expense using a systematic and rational method and the liabilities are accreted to measure the change in liability due to the passage of time. The provisions of this standard primarily apply to dismantlement and site restoration of certain of our plants and pipelines. We have evaluated our asset retirement obligations as of December 31, 2006 and have determined that revisions in the carrying values are not necessary at this time.

The following table summarizes our activity related to asset retirement obligations:

Asset retirement obligation, January 1, 2005	$ 619
Add: acquired from Hiland Partners, LLC on February 15, 2005	398
Add: accretion expense	27
Less: revisions	(20)
Asset retirement obligation, December 31, 2005	1,024
Acquired in Kinta Area asset acquisition on May 1, 2006	1,106
Add: accretion expense	66
Asset retirement obligation, December 31, 2006	$ 2,196

Recently Issued Accounting Pronouncements

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities . SFAS No. 159 expands opportunities to use fair value measurement in financial reporting and permits entities to choose to measure many financial instruments and certain other items at fair value. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. We have not decided if we will early adopt SFAS No. 159 or if we will choose to measure any eligible financial assets and liabilities at fair value.

In September 2006, the FASB issued SFAS No. 157 Fair Value Measurements. SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP) such as fair value hierarchy used to classify the source of information used in fair value measurements (i.e., market based or non-market based) and expands disclosure about fair value measurements based on their level in the hierarchy. This Statement applies to derivatives and other financial instruments, which Statement 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended requires be measured at fair value at initial recognition and for all subsequent periods. This Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. We will apply the provisions of the Statement prospectively in our first interim period in the fiscal year beginning on January 1, 2008 and we do not expect a change in our methodologies of fair value measurements.

In September 2006, the SEC staff issued Staff Accounting Bulletin No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements. SAB 108 was issued to provide consistency between how registrants quantify financial statement misstatements. Historically, there have been two widely used methods for quantifying the effects of financial statement misstatements. These methods are referred to as the roll-over and iron curtain method. The roll-over method quantifies the amount by which the current year income statement is misstated. Exclusive reliance on an income statement approach can result in the accumulation of errors on the balance sheet that may not have been material to any individual income statement, but which may misstate one or more balance sheet accounts. The iron curtain method quantifies the error as the cumulative amount by which the current year balance sheet is misstated. Exclusive reliance on a balance sheet approach can result in disregarding the effects of errors in the current year income statement that results from the correction of an error existing in previously issued financial statements. SAB 108 established an approach that requires quantification of financial statement misstatements based on the effects of the misstatement on each of the company s financial statements and the related financial statement disclosures. This approach is commonly referred to as the dual approach because it requires quantification of errors under both the roll-over and iron curtain methods. We applied the methodology consistent with SAB 108 in connection with the preparation of these annual financial statements for the year ending December 31, 2006 and did not record an adjustment.

Note 2: 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, after redemption of 195,991 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 CGI 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 15, 2005
(in thousands)

	Continental Gas, Inc. (Predecessor) February 14, 2005	Net Assets Not Contributed	Contributed to Hiland Partners, LP 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	