Regency Energy Partners LP
Form 10-K
March 30, 2007

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2006

OR

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

Commission file number: 0001-338613

REGENCY ENERGY PARTNERS LP
(Exact name of registrant as specified in its charter)

Delaware *(State or other jurisdiction of incorporation or organization)*	**16-1731691** *(I.R.S. Employer Identification No.)*
1700 Pacific Avenue, Suite 2900 Dallas, Texas *(Address of principal executive offices)*	**75201** *(Zip Code)*

(214) 750-1771
(Registrant s telephone number, including area code)

(Former name, former address and former fiscal year, if changed since last report):
[None]

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Units of Limited Partner Interests	The Nasdaq Stock Market LLC

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 the Securities Act. Yes o No þ

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, 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 o Non-accelerated filer þ

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

As of June 30, 2006, the aggregate market value of the registrant s common stock held by non-affiliates of the registrant was $397,341,000 based on the closing sale price as reported on the National Association of Securities Dealers Automated Quotation System National Market System.

Indicate the number of outstanding units of each of the registrant s classes of units, as of the latest practicable date.

Class	**Outstanding at March 22, 2007**
Common Units	27,844,291
Subordinated Units	19,103,896

DOCUMENTS INCORPORATED BY REFERENCE

None.

REGENCY ENERGY PARTNERS LP
ANNUAL REPORT ON FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2006

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Introductory Statement

References in this report to Regency Energy Partners, we, our, us and similar terms, when used in an histori context, refer to Regency Energy Partners LP, or the Partnership, and to Regency Gas Services LLC, all the outstanding member interests of which were contributed to the Partnership on February 3, 2006, and its subsidiaries. When used in the present tense or prospectively, these terms refer to the Partnership and its subsidiaries. References to our general partner or the General Partner refer to Regency GP LP, the general partner of the Partnership. References to the Managing GP refer to Regency GP LLC, the general partner of the General Partner, which effectively manages the business and affairs of the Partnership. References to HM Capital refer to HM Capital Partners LLC. References to HM Capital Investors refer to Regency Acquisition LP, HMTF Regency L.P., HM Capital and funds managed by HM Capital, including the Hicks, Muse, Tate & Furst Equity Fund V, L.P., and certain co-investors, including some of the directors and officers of the Managing GP. Regency Acquisition LP is wholly owned by HMTF Regency L.P., which, in turn, is wholly owned by HM Capital, funds managed by HM Capital and certain co-investors.

Cautionary Statement about Forward-Looking Statements

Certain matters discussed in this report include 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. Forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. Statements using words such as anticipate, believe, intend, project, plan, expect, continue, estimate, goal, similar expressions help identify forward-looking statements. Although we believe our forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, we can not give assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions including without limitation the following:

- **changes in laws and regulations impacting the midstream sector of the natural gas industry;**
- **the level of creditworthiness of our counterparties;**
- **our ability to access the debt and equity markets;**
- **our use of derivative financial instruments to hedge commodity and interest rate risks;**
- **the amount of collateral required to be posted from time to time in our transactions;**
- **changes in commodity prices, interest rates, demand for our services;**
- **weather and other natural phenomena;**
- **industry changes including the impact of consolidations and changes in competition;**
- **our ability to obtain required approvals for construction or modernization of our facilities and the timing of production from such facilities; and**
- **the effect of accounting pronouncements issued periodically by accounting standard setting boards.**

If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may differ materially from those anticipated, estimated, projected or expected.

Other factors that could cause our actual results to differ from our projected results are discussed in Item 1A of this annual report.

Each forward-looking statement speaks only as of the date of the particular statement and we undertake no obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

PART I

Item 1. *Business*

OVERVIEW

We are a growth-oriented publicly-traded Delaware limited partnership engaged in the gathering, processing, marketing and transportation of natural gas. We provide these services through systems located in north Louisiana, Texas and the mid-continent region of the United States, which includes Kansas, Oklahoma, Colorado and the Texas Panhandle. We were formed in April 2005 by HM Capital to capitalize on opportunities in the midstream sector of the natural gas industry.

We divide our operations into two business segments:

Gathering and Processing: in which we provide wellhead-to-market services to producers of natural gas, which include transporting raw natural gas from the wellhead through gathering systems, processing raw natural gas to separate natural gas liquids, or NGLs, from the raw natural gas and selling or delivering the pipeline-quality natural gas and NGLs to various markets and pipeline systems; and

Transportation: in which we deliver natural gas from northwest Louisiana to more favorable markets in northeast Louisiana through our 320-mile Regency Intrastate Pipeline system, which has been significantly expanded and extended over the last 18 months.

All of our assets are located in well-established areas of natural gas production that are characterized by long-lived, predictable reserves. These areas are generally experiencing increased levels of natural gas exploration, development and production activities as a result of strong demand for natural gas, attractive recent discoveries, infill drilling opportunities and the implementation of new exploration and production techniques.

BUSINESS STRATEGIES

Our management team is dedicated to increasing the amount of cash available for distribution to each outstanding unit while maintaining financial flexibility. We intend to achieve this by executing the following strategies:

Maximizing the profitability of our existing assets. We intend to increase the profitability of our existing asset base by actively controlling and reducing operating costs, identifying new business opportunities, scaling our operations by adding new volumes of natural gas supplies and undertaking additional initiatives to enhance efficiency.

Implementing cost-effective organic growth opportunities. We intend to build natural gas gathering assets, processing facilities and transportation lines that will enhance our existing systems, further our ability to aggregate supply, and enable us to access premium markets for that supply. Where applicable, we will seek to coordinate each expansion with the needs of significant producers in the area to mitigate speculative risk associated with securing through-put volumes.

Pursuing accretive acquisitions of complementary assets. We intend to pursue strategic acquisitions of midstream assets in or near our current areas of operation that offer the opportunity for operational efficiencies and the potential for increased utilization and expansion of those assets. As in the case of our acquisition of

TexStar (see Recent Developments-TexStar Acquisition below), we also intend to pursue opportunities in new regions with significant natural gas reserves and high levels of drilling activity. We believe that there will be additional acquisition opportunities as a result of the ongoing divestiture of midstream assets by large industry participants.

Continuing to reduce our exposure to commodity price risk. We operate our business in a manner that allows us to generate stable cash flows, while mitigating the impact of fluctuations in commodity prices. We manage our commodity price exposure through an integrated strategy that includes:

- actively managing our contract portfolio;
- pursuing new fee-based business opportunities;
- matching the indices used for purchases and sales of commodities;
- optimizing our portfolio by monitoring basis and other price differentials in our areas of operations; and
- executing a comprehensive hedging strategy using swap contracts settled against natural gas, crude oil, ethane, propane, butane and natural gasoline to mitigate expose to commodity prices.

Improving our credit ratings and maintaining a flexible capital structure. We are committed to improving our credit ratings. We intend to finance our growth projects through a combination of funds available under our credit facility, commercial bank borrowings and the issuance of debt and equity securities.

COMPETITIVE STRENGTHS

We believe that we are well positioned to execute our business strategies and to compete in the natural gas gathering, processing, marketing and transportation businesses based on the following competitive strengths:

We have a significant market presence in major natural gas supply areas. We have a significant market presence in each of our operating areas, which are located in some of the largest and most prolific gas-producing regions of the United States: the Louisiana-Mississippi-Alabama Salt basin in north Louisiana, the Permian basin of west Texas, the Hugoton and Anadarko basins in the mid-continent area, the East Texas basin and Edwards, Olmos and Wilcox trends in south Texas. Our geographical diversity reduces our reliance on any particular region, basin or gathering system. Each of these producing regions is well-established with generally long-lived, predictable reserves, and our assets are strategically located in each of the regions. These areas are generally experiencing increased levels of natural gas exploration, development and production activities as a result of strong demand for natural gas, attractive recent discoveries, infill drilling opportunities and the implementation of new exploration and production techniques.

Our Regency Intrastate Gas System provides us with significant fee-based transportation through-put volumes and cash flow. The Regency Intrastate Gas System allows us to capitalize on the flow of natural gas from producing fields in north Louisiana to intrastate and interstate markets in northeast Louisiana. These transportation through-put volumes have limited commodity price exposure and provide us with a stable, fee-based cash flow.

We have the financial flexibility to pursue growth opportunities. We remain committed to maintaining a capital structure that will afford us the financial flexibility to fund expansion projects and other attractive investment opportunities. We believe our ability to access capital and our credit facility provide us with the liquidity and financial flexibility we will need to execute our business strategy.

We have an experienced, knowledgeable management team with a proven track record. Our senior management has an average of over 20 years of industry related experience. Our team s extensive experience and contacts within the midstream industry provide a strong foundation and focus for managing and enhancing our operations, for accessing strategic acquisition opportunities and for constructing new assets. Additionally, members of our senior management team have a substantial economic interest in us.

W*e are affiliated with HM Capital, a leading private equity investment firm.* Our affiliation with HM Capital has provided us and we expect will continue to provide us with several significant benefits,

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including access to a significant pool of operational, transactional and financial professionals, multiple sources of capital and increased exposure to acquisition opportunities. HM Capital is a leading sector focused private equity firm headquartered in Dallas, Texas and is currently managing and investing a $1.6 billion fund. Since the firm s founding in 1989, HM Capital has completed more than 150 transactions in its core sectors for a total transaction value in excess of $26 billion.

RECENT DEVELOPMENTS

TexStar Acquisition

On August 15, 2006, we completed the acquisition of all the outstanding equity of TexStar Field Services, L.P. and its general partner, TexStar GP, LLC (together TexStar), from an affiliate of HM Capital. The total purchase price for TexStar was $348,909,000, which consisted of $62,074,000 in cash, the issuance of 5,173,189 Class B common units valued at $119,183,000 to an affiliate of HM Capital, and the assumption of $167,652,000 of TexStar s outstanding bank debt. We financed the cash portion of the purchase price and repaid TexStar s assumed bank debt through borrowings under our amended and restated credit facility discussed below. TexStar was a midstream natural gas company that provided gathering, compression, treating and processing services to gas producers in south and east Texas.

We believe that the TexStar assets give us attractive competitive positions in east Texas and south Texas. The east Texas assets are strategically located in an area that has experienced a recent increase in development activity. Furthermore, the combined assets provide us with significant geographical diversity, increasing the key regions in which we operate from three to five.

Amended and Restated Credit Facility

In connection with the acquisition of TexStar, we amended and restated our $470,000,000 credit agreement in order to increase the credit facility to $850,000,000, consisting of $600,000,000 in term loans and $250,000,000 in a revolving credit facility, and to increase the availability for letters of credit to $100,000,000. In addition, we have the option to increase the commitments under the revolving credit facility or the term loan facility, or both, by an amount up to $200,000,000 in the aggregate, subject to obtaining commitments therefore. Subsequent to the issuance of senior notes, we reduced the amounts outstanding under the term facility to $50,000,000 and decreased the capacity of our credit facility to $300,000,000. For additional information regarding our credit facility, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Requirements Fourth Amended and Restated Credit Facility.

Debt Private Placement

In December 2006, the Partnership and Regency Energy Finance Corp., a wholly-owned subsidiary of Regency Gas Services LP, issued $550,000,000 of senior notes (senior notes) that mature on December 15, 2013 in a private placement to qualified institutional buyers. The senior notes bear interest at 8.375 percent and interest is payable semi-annually in arrears on each June 15 and December 15, commencing on June 15, 2007. We used the proceeds from the private placement to repay $550,000,000 in term loans outstanding under our credit facility.

Equity Private Placement

In September 2006, we sold 2,857,143 Class C common units directly to certain purchasers in a private placement for $59,942,000, including transaction costs. We used the proceeds from the private offering to repay borrowings under our credit facility that were incurred to fund the TexStar acquisition.

The Class B and C common units converted into common units on February 8, 2007 and February 15, 2007, respectively. Promptly after the filing of this Annual Report with the Securities and Exchange Commission, we intend to file a registration statement with the SEC in order to register the offering and sale

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of certain of the common units into which the Class B and Class C common units were converted in accordance with applicable registration rights agreements.

INDUSTRY OVERVIEW

General. Raw natural gas produced from the wellhead is gathered and delivered to a processing plant located near the production, where it is treated, dehydrated, and/or processed. Natural gas processing involves the separation of raw natural gas into pipeline quality natural gas, principally methane, and mixed NGLs. Natural gas treating entails the removal of impurities, such as water, sulfur compounds, carbon dioxide and nitrogen. Pipeline-quality natural gas is delivered by interstate and intrastate pipelines to markets. Mixed NGLs are typically transported via NGL pipelines or by truck to a fractionator, which separates the NGLs into its components, such as ethane, propane, butane, isobutane and natural gasoline. The component NGLs are then sold to end users.

The following diagram depicts our role in the process of gathering, processing, marketing and transporting natural gas.

Overview of U.S. market. The midstream natural gas industry is the link between exploration and production of raw natural gas and the delivery of its components to end-use markets. According to the Energy Information Administration, or EIA, the midstream natural gas industry in the United States includes approximately 530 processing plants that process approximately 42 Bcf of natural gas per day and produce approximately 76 million gallons per day of NGLs. The midstream industry is generally characterized by regional competition based on the proximity of gathering systems and processing plants to natural gas wells. Natural gas remains a critical component of energy consumption in the United States. According to the EIA, total annual domestic consumption of natural gas is expected to increase from 21.98 trillion cubic feet, or Tcf, in 2005 to 26.26 Tcf in 2020, representing an average annual growth rate of 1.3 percent. During the five years ended December 31, 2005, the United States has on average consumed approximately 22.4 Tcf per year, while total marketed domestic production averaged approximately 19.8 Tcf per year during the same period. The industrial and electricity generation sectors currently account for the largest usage of natural gas in the United States.

Gathering. A gathering system typically consists of a network of small diameter pipelines and, if necessary, a compression system which together collect natural gas from points near producing wells and transport it to larger pipelines for further transportation. We own and operate large gathering systems in five geographic regions of the United States.

Compression. Gathering systems are operated at design pressures that seek to maximize the total through-put volumes from all connected wells. Since wells produce at progressively lower field pressures as they age, the raw natural gas must be compressed to deliver the remaining production against a higher pressure that exists in the connected gathering system. Natural gas compression is a mechanical process in which a volume of gas at a lower pressure is boosted, or compressed, to a desired higher pressure, allowing gas that no longer naturally flows into a higher pressure downstream pipeline to be brought to market. Field compression is typically used to lower the entry pressure, while maintaining or increasing the exit pressure of a gathering system to allow it to operate at a lower receipt pressure and provide sufficient pressure to deliver gas into a higher pressure downstream pipeline.

Processing and treating. Raw natural gas produced at the wellhead is often unsuitable for long-haul pipeline transportation or commercial use and must be processed and/or treated to remove the heavier hydrocarbon components and/or contaminants. The principal components of pipeline-quality natural gas are methane and ethane, but most raw natural gas also contains varying amounts of NGLs (such as ethane, propane, normal butane, isobutane, and natural gasoline) and impurities, such as water, sulfur compounds, carbon dioxide, or nitrogen. We own and operate natural gas processing and/or treating plants in five geographic regions.

Fractionation. NGL fractionation facilities separate mixed NGL streams into discrete NGL products: ethane, propane, butane, isobutane and natural gasoline. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Propane is used both as a petrochemical feedstock in the production of propylene and as a heating fuel, an engine fuel and an industrial fuel. Normal butane is used as a petrochemical feedstock in the production of butadiene (a key ingredient in synthetic rubber), and as a blend stock for motor gasoline. Isobutane is typically fractionated from mixed butane (a stream of normal butane and isobutane in solution), principally for use in enhancing the octane content of motor gasoline. Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is used primarily as motor gasoline blend stock or petrochemical feedstock. We do not own or operate any NGL fractionation facilities.

Marketing. Natural gas marketing involves the sale of the pipeline-quality gas either produced by processing plants or purchased from gathering systems or other pipelines. We perform a limited natural gas marketing function for our account and for the accounts of our customers based upon the location of our assets.

Transportation. Natural gas transportation consists of moving pipeline-quality natural gas from gathering systems, processing plants and other pipelines and delivering it to wholesalers, utilities and other pipelines. We own and operate the Regency Intrastate Pipeline system, an intrastate natural gas pipeline system located in north Louisiana. We also own a 10-mile pipeline that extends from Harrison County, Texas to Caddo Parish, Louisiana.

GATHERING AND PROCESSING OPERATIONS

General

We operate significant gathering and processing assets in five geographic regions of the United States: north Louisiana, the mid-continent, and east, south, and west Texas. We contract with producers to gather raw natural gas from individual wells or central delivery points, which may have multiple wells behind them, located near our processing plants or gathering systems. Following the execution of a contract, we connect wells and central delivery points to our gathering lines through which the raw natural gas flows to a processing plant, treating facility or directly to interstate or intrastate gas transportation pipelines. At our processing plants, we remove any impurities in the raw natural gas stream, and extract the NGLs. Our gathering and processing operations are located in areas that have experienced significant levels of drilling activity, providing us with opportunities to access newly developed natural gas supplies. One of our customers represented 17 percent of the natural gas supply in our gathering and processing segment for the year ended December 31, 2006.

All raw natural gas flowing through our gathering and processing facilities is supplied under gathering and processing contracts having fixed terms ranging from month-to-month to the life of the oil and gas lease. For a description of our contracts, please read Our Contracts and Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Our Operations.

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The pipeline-quality natural gas remaining after separation of NGLs through processing is either returned to the producer or sold, for our own account or for the account of the producer, at the tailgates of our processing plants for delivery through interstate or intrastate gas transportation pipelines.

The following table sets forth information regarding our gathering systems and processing plants as of December 31, 2006.

Asset	Length (Miles)	Compression (Horsepower)	Through-Put Volume Capacity (MMcf/d)
North Louisiana			
Dubach/Calhoun/Lisbon Gathering System	600	24,255	300
Dubach Processing Plant		9,554	50
Lisbon Processing Plant		4,863	40
Elm Grove Refrigeration Plant			200
Dubberly Refrigeration Plant			200
Haughton Refrigeration Plant(1)			35
East Texas			
Eustace Gathering System	314	8,784	100
Eustace Processing Plant		8,620	65
Como Gathering System	57	280	50
Como Processing Plant(2)		5,911	35
South Texas			
Tilden Gathering System	146		400
Tilden Processing Plant		2,400	115
Mainline Gathering System	305	2,573	75
Various Other Gathering Systems	562	2,487	295
Palafox Gathering System	34	9,592	30
Eagle Pass Processing Plant			10
West Texas			
Waha Gathering System	750	32,296	200
Waha Processing Plant		8,536	125
Mid-Continent(3)			
Hugoton Gathering System	850	27,502	120
Mocane-Laverne Gathering System	500	3,025	100
Greenwood Gathering System	250	9,350	40
Mocane Processing Plant			50
Wheeler County Processing Plant			5

(1) The 35 MMcf/d Haughton refrigeration plant is accounted for in our Transportation segment.

(2) The Como processing plant was taken out of service in March 2007 and the Como Gathering System volumes were routed to our Eustace Processing Plant.

(3) Excludes 80 MMcf/d of through-put capacity available at our inactive Lakin processing facility.

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North Louisiana Region

Our north Louisiana region includes the Dubach and Lisbon processing plants and the Dubach/ Calhoun/ Lisbon gathering system, which is a large integrated natural gas gathering and processing system located primarily in four parishes of north Louisiana and includes 600 miles of gathering pipelines.

The following is a map of our north Louisiana gathering and processing system.

This system is located in active drilling areas in north Louisiana. Through our Dubach/Calhoun/Lisbon gathering system and its interconnections with our Regency Intrastate Pipeline system in north Louisiana described in Transportation Operations, we offer producers wellhead-to-market services, including natural gas gathering, compression, processing, marketing and transportation.

Natural Gas Supply. The natural gas supply for our north Louisiana gathering systems is derived primarily from natural gas wells located in Claiborne, Union, Lincoln and Ouachita Parishes in north Louisiana. Our operating areas have experienced significant levels of drilling activity, providing us with opportunities to access newly developed natural gas supplies. Natural gas production in this area has increased as a result of the additional drilling, which includes deeper reservoirs in the Cotton Valley and Hosston trends.

Dubach/Lisbon/Calhoun Gathering System. The Dubach/ Lisbon/ Calhoun gathering system consists of 600 miles of natural gas gathering pipelines ranging in size from two inches to 10 inches in diameter. The system gathers raw natural gas from producers and delivers approximately 85 percent of the raw natural gas to either the Dubach or Lisbon processing plant for processing. The remainder of the raw natural gas is lean natural gas, which does not require processing and is delivered directly to interstate pipelines and our Regency Intrastate Pipeline system.

Dubach Processing Plant. The Dubach processing plant is a cryogenic natural gas processing plant that processes raw natural gas gathered on the Dubach and Calhoun gathering systems. This plant, which was acquired by us in 2003, was originally constructed in 1980 and was subsequently reassembled in its present location in 1994.

Lisbon Processing Plant. The Lisbon processing plant is a cryogenic natural gas processing plant that processes raw natural gas gathered on the Lisbon gathering system. This plant, which was acquired by us in 2003, was constructed in 1980 and was subsequently reassembled in its present location in 1996.

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Elm Grove and Dubberly Refrigeration Plants. The Elm Grove and Dubberly refrigeration plants process raw natural gas located in Bossier and Webster parishes in northeastern Louisiana. Elm Grove was placed into service in May 2006 and Dubberly was placed into service in December 2006.

East Texas Region

Our east Texas region includes:

the Eustace Gathering System, a large integrated natural gas gathering and processing system located in Rains, Wood, Van Zandt and Henderson Counties and includes 314 miles of gathering pipelines and 8,784 horsepower of field compression and flows into the Eustace processing plant; and

the Como Gathering System, which is a smaller integrated natural gas gathering and processing system located in Franklin, Wood, Hopkins and Rains Counties and includes 57 miles of gathering pipelines and 280 horsepower of field compression and flows into the Como processing plant.

These east Texas gathering assets gather, compress and dehydrate natural gas. Natural gas produced in this region is high in hydrogen sulfide content. Both systems are connected to processing and treating facilities that include sulfur removal units.

The following is a map of our east Texas gathering and processing systems:

Natural Gas Supply. The natural gas supply for our east Texas gathering systems is derived primarily from natural gas wells located in east Texas. These wells are located in a mature basin and generally have long lives and predictable gas flow rates.

Eustace Processing Plant. The Eustace Processing Plant is a cryogenic natural gas processing plant that was constructed in its current location in 1981. It includes a 70 MMcf/d amine treating unit, a 50 MMcf/d cryogenic NGL recovery unit and an 840 ton liquid (per day) sulfur recovery unit. This plant removes hydrogen sulfide from the natural gas stream, which in this region contains a high concentration of hydrogen sulfide, recovers NGLs and condensate, delivers pipeline quality gas at the plant outlet and produces sulfur.

Como Processing Plant. The Como Processing Plant is a cryogenic natural gas processing plant that was constructed in its current location in 1964. It includes a 35 MMcf/d amine treating unit and nitrogen recovery unit and a 200 ton (per day) liquid sulfur unit. The plant facilities were used to remove hydrogen

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sulfide from the natural gas stream, to recover NGLs and condensate, to deliver pipeline quality gas at the plant outlet and to produce sulfur. As planned in connection with the TexStar acquisition, the Como Processing Plant was removed from active service in March 2007 and all gas deliveries were routed to the Eustace Processing Plant.

South Texas Region

Our south Texas region primarily includes the following natural gas gathering systems located in various counties in south Texas.

- the Tilden Gathering System, a large integrated natural gas gathering and processing system located in McMullen, Atascosa, Frio and LaSalle Counties in south Texas and includes 146 miles of gathering pipelines and 2,400 horsepower of field compression and flows into the Tilden Processing Plant.

- the Palafox Gathering System includes natural gas gathering pipelines owned by the Palafox joint venture (which, until February 1, 2007, was 50 percent owned by us and operated by the other joint venture partner) and another small gathering system that we own and operate. On February 1, 2007, we purchased the 50 percent joint venture interest of the other party to the joint venture for $5,000,000 in cash. Together, the pipelines aggregate 34 miles and have a capacity through-put of 30 MMcf/d. Currently, natural gas gathered by this system is delivered to a third party for processing. The system is in proximity to our other south Texas assets and we plan to connect the system to our other assets in the near future.

The following is a map of our south Texas gathering and processing systems:

Natural Gas Supply. The natural gas supply for our south Texas gathering systems is derived primarily from natural gas wells located in the area. These wells are located in a mature basin and generally have long lives and predictable gas flow rates.

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These south Texas gathering assets gather, compress and dehydrate natural gas. Some of the natural gas produced in this region can have significant hydrogen sulfide content. These systems are connected to processing and treating facilities that include sulfur removal units.

Tilden Processing Plant. The Tilden Processing Plant is a natural gas treating plant that was constructed in its current location in 1981. It includes inlet compression, a 60 MMcf/d amine treating unit, a 55 MMcf/d amine treating unit and a 40 ton (per day) liquid sulfur recovery unit. In addition, it includes a second 55 MMcf/d amine treating unit and a 20 ton (per day) liquid sulfur recovery unit, both of which are currently inactive. This plant removes hydrogen sulfide from the natural gas stream, which in this region often contains a high concentration of hydrogen sulfide, recovers condensate, delivers pipeline quality gas at the plant outlet and produces sulfur.

West Texas Region

Our west Texas region includes the Waha gathering system and the Waha processing plant. The following is a map of our Waha gathering and processing system:

The system covers four Texas counties surrounding the Waha Hub, one of Texas major natural gas market areas. Through our Waha gathering system, we offer producers wellhead to market services. As a result of the proximity of this system to the Waha Hub, the Waha gathering system has a variety of market outlets for the natural gas that we gather and process, including several major interstate and intrastate pipelines serving California, the mid-continent region of the United States and Texas natural gas markets.

Natural Gas Supply. The natural gas supply for the Waha gathering system is derived primarily from natural gas wells located in four counties in west Texas near and around the Waha Hub. Natural gas exploration and production drilling in this area has primarily targeted productive zones in the Permian Delaware basin and Devonian basin. These basins are mature basins with wells that generally have long lives and predictable flow rates.

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Waha Gathering System. The Waha gathering system consists of 750 miles of natural gas gathering pipelines ranging in size from three inches in diameter to 24 inches in diameter. We offer producers four different levels of natural gas compression on the Waha gathering system, as compared to the two levels typically offered in the industry. By offering multiple levels of compression, our gathering system is often more cost-effective for our producers, since the producer is not required to pay for a level of compression that is higher than the level it requires.

Waha Processing Plant. The Waha processing plant is a cryogenic natural gas processing plant that processes raw natural gas gathered on the Waha gathering system. This plant was constructed in 1965, and, due to recent upgrades to state of the art cryogenic processing capabilities, it is a highly efficient natural gas processing plant. The Waha processing plant also includes an amine treating facility. The treating facility uses an amine treating process to remove carbon dioxide and hydrogen sulfide from raw natural gas that is gathered in our Waha gathering system before the natural gas is introduced to the processing plant.

Mid-Continent Region

Our mid-continent region includes natural gas gathering systems located primarily in Kansas and Oklahoma. Our mid-continent gathering assets are extensive systems that gather, compress and dehydrate low-pressure gas from approximately 1,500 wells. These systems are geographically concentrated, with each central facility located within 90 miles of the others. We operate our mid-continent gathering systems at low pressures to increase the total through-put volumes from the connected wells. Wellhead pressures are therefore adequate to access the gathering lines without the cost of wellhead compression. In addition, we process natural gas from the Mocane-Laverne Gathering System at our Mocane Processing Plant.

The following is a map of our Mid-Continent Region gathering and processing systems.

Natural Gas Supply. Our mid-continent systems are located in two of the largest and most prolific natural gas producing regions in the United States, including the Hugoton Basin in southwest Kansas and the Anadarko Basin in western Oklahoma and the Texas panhandle. These mature basins have continued to

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provide generally long-lived, predictable reserves. Recent increases in production in these areas have been driven primarily by continued infill drilling, compression enhancements, and advanced well bore completion technology. In addition, the application of 3-D seismic technology in these areas has yielded better-defined reservoirs for continuing development of these basins.

Hugoton Gathering System. The Hugoton gathering system is located in southwestern Kansas. It consists of 850 miles of natural gas gathering pipelines ranging in size from two inches to 20 inches in diameter. Substantially all of the raw natural gas gathered by the Hugoton gathering system is delivered to a third party s processing plant. We pay the third party a fee to process the gas for our account.

Mocane-Laverne Gathering System. The Mocane-Laverne gathering system is located in Beaver and Harper counties in the Oklahoma panhandle and Meade County in southwestern Kansas. It consists of 500 miles of natural gas gathering pipelines ranging in size from two inches to 24 inches in diameter. The system gathers raw natural gas from producers and delivers it for processing to the Mocane processing plant.

Greenwood Gathering System. The Greenwood gathering system is located in Morton and Stanton Counties in southwestern Kansas and Baca County in southeastern Colorado. It consists of 250 miles of natural gas gathering pipelines ranging in size from four inches to 20 inches in diameter. The raw natural gas gathered by this system is delivered to a third party s processing plant. We pay the third party a fee to process the gas for our account.

Mocane Processing Plant. The Mocane Processing Plant is a cryogenic natural gas processing plant that processes raw natural gas gathered on the Mocane-Laverne gathering system. This plant was constructed in 1975 and acquired by us in 2003.

Other. We also own the Lakin Processing Plant, a cryogenic processing plant with nitrogen rejection and helium recovery capabilities. This plant has a capacity of 80 MMcf/d. The plant was constructed in 1995 and was acquired by us in 2003. We are currently evaluating opportunities to utilize the Lakin processing plant, which may include connecting a new source of supply to the plant or moving the plant to another area.

TRANSPORTATION OPERATIONS

General. We own and operate a 320-mile intrastate natural gas pipeline system, known as the Regency Intrastate Pipeline system, in north Louisiana extending from northwest Louisiana to northeast Louisiana. This system includes total system capacity of 910 MMcf/d, 27,400 horsepower of compression and a 35 MMcf/d refrigeration plant. The following map presents the location of the Regency Intrastate Pipeline system:

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Regency Intrastate Pipeline system averaged through-put volumes of 587,098 MMBtu/d during the year ended December 31, 2006. Natural gas generally flows from west to east on the pipeline from wellhead connections or connections with other gathering systems. The Regency Intrastate Pipeline system transports natural gas produced from the Vernon field, the Elm Grove field and the Sligo field, which are the three of the four largest natural gas producing fields in Louisiana.

Our Regency Intrastate Pipeline consists of approximately 320 miles of pipeline ranging from 12 to 30 diameter, extending from Caddo Parish to Franklin Parish in northern Louisiana.

Our transportation operations are located in areas that have experienced significant levels of drilling activity providing us with opportunities to access newly developed natural gas supplies. Three customers represented 19 percent, 15 percent and 10 percent of our transportation segment natural gas supply for the year ended December 31, 2006.

A significant purchaser of pipeline-quality gas on the Regency Intrastate Pipeline system is Alabama Gas Corporation, which represented 11 percent of consolidated external revenues from such sales for the year ended December 31, 2006.

New Transportation Contracts. As of March 1, 2007, we had definitive agreements (with terms ranging from less than one year to five years for 562,900 MMBtu/d of firm transportation on the Regency Intrastate Pipeline System, of which 500,679 MMBtu/d was utilized in February 2007. During the month of February 2007, we also provided 195,395 MMBtu/d of interruptible transportation. Additionally, we are currently engaged in discussions with other parties interested in utilizing the system s remaining firm transportation.

Eastside Compressor Fire. On March 18, 2007, a fire occurred at the Eastside Compressor Station on our Regency Intrastate Pipeline system. Of the three compressor units in the station, one was damaged beyond repair, the second unit sustained reparable damage and the third was slightly damaged. The third unit was restored to service in 40 hours and the second is expected to be back in service in six to eight weeks. There were no personal injuries as a result of the incident. We are moving two smaller surplus compressors to the site which we expect to be operating in the first week of April. Another rental compressor is expected to be operating by the second week of April. The replacement unit for the severely damaged compressor is not expected to be in service for about six months. Pending installation of the rental compressors and the restoration of the second unit to service, we are managing the system with existing compressors on other parts of the system and with careful gas management. Thereafter, we expect little or no effect on our ability to maintain pre-incident levels of gas flow. The Louisiana Department of Environmental Quality has granted a request for an emissions variance for the temporary compressors. While preliminary estimates of property damage are in the range of $5,000,000 to $6,500,000, the equipment is fully insured, subject to a deductible of $250,000. To date, this incident has had no material effect on our business. We anticipate that through careful management of the system we will be able to mitigate any material disruption to our business. If we are unable to do so, however, we maintain business interruption insurance that we believe will protect us against any materially adverse financial effect. Our business interruption insurance is subject to a deductible for losses and expenses incurred during the first 30 days following an incident which will include our costs of mobilizing and installing the rental compressors, estimated at $600,000.

OTHER TRANSPORTATION ASSETS

Gulf States Transmission, our interstate pipeline, consists of 10 miles of 12 inches in diameter and 20 inches in diameter pipeline that extends from Harrison County, Texas to Caddo Parish, Louisiana. The pipeline has a Federal Energy Regulatory Commission (FERC) certificated capacity of 150 MMcf/d.

OUR CONTRACTS

Gathering and Processing Contracts

We contract with producers to gather raw natural gas from individual wells or central delivery points located near our gathering systems and processing plants. Following the execution of a contract with the producer, we connect the producer s wells or central delivery points to our gathering lines through which the

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natural gas is delivered to a processing plant (whether owned and operated by us or a third party) for a fee. We obtain supplies of raw natural gas for our gathering and processing facilities under contracts having terms ranging from month-to-month to life of the lease. We categorize our processing contracts in increasing order of commodity price risk as fee-based, percentage-of-proceeds, or keep-whole contracts. Additionally, it is common for a percentage-of-proceeds or keep-whole contract to have a fee component in addition to its commodity price-sensitive component. For a description of our fee-based arrangements, percent-of-proceeds arrangements, and keep-whole arrangements, please read Item 7 Management s discussion and analysis of financial condition and results of operations Our Operations. During the twelve months ended December 31, 2006, purchases from Duke Energy Field Services made up 12 percent of the volumes represented as the cost of gas and liquids on our consolidated statement of operations.

For the year ended December 31, 2006, the mixture of our gathering and processing contracts by category and by geographic region is set forth in the following table:

	Nature of Contract (Measured by 2006 Volumes)		
Geographic Region	**Keep-Whole**	**POP**	**Fee-Based**
North Louisiana	9%	39%	52%
East Texas		100	
South Texas	1	10	89
West Texas	14	57	29
Mid-Continent	26	46	28
Total Gathering and Processing	12	41	47

Transportation Contracts

Fee Transportation Contracts. We provide natural gas transportation services on the Regency Intrastate Pipeline pursuant to contracts with natural gas shippers. These contracts are all fee-based. Generally, our transportation services are of two types: firm transportation and interruptible transportation. When we agree to provide firm transportation service, we become obligated to transport natural gas nominated by the shipper up to the maximum daily quantity specified in the contract. In exchange for that obligation on our part, the shipper pays a specified reservation charge, whether or not the capacity is utilized by the shipper, and in some cases the shipper also pays a commodity charge with respect to quantities actually shipped. When we agree to provide interruptible transportation service, we become obligated to transport natural gas nominated and actually delivered by the shipper only to the extent that we have available capacity. The shipper pays no reservation charge for this service but pays a commodity charge for quantities actually shipped. We provide our transportation services under the terms of our contracts and under an operating statement that we have filed and maintain with FERC with respect to transportation authorized under Section 311 of the Natural Gas Policy Act of 1978, or NGPA.

Merchant Transportation Contracts. We perform a limited merchant function on our Regency Intrastate Pipeline system. We purchase natural gas from producers or gas marketers at receipt points on our system at a price adjusted to reflect our transportation fee and transport that gas to delivery points on our system at which we sell the natural gas at market price. We regard the total segment margin with respect to those purchases and sales as the economic equivalent of a fee for our transportation service.

These contracts are frequently settled in terms of an index price for both purchases and sales. In order to minimize commodity price risk, we attempt to match sales with purchases at the same index price on the date of settlement.

COMPETITION

The natural gas gathering, processing, marketing and transportation businesses are highly competitive. We face strong competition in each region in acquiring new gas supplies. Our competitors in acquiring new gas supplies and in processing new natural gas supplies include major integrated oil companies, major interstate and intrastate pipelines and other natural gas gatherers that gather, process and market natural gas. Competition for natural gas supplies is primarily based on the reputation, efficiency and reliability of the gatherer and the pricing arrangements offered by the gatherer.

Many of our competitors have capital resources and control supplies of natural gas substantially greater than ours. Competition in natural gas transportation is characterized by price of transportation, the nature of the markets accessible from a transportation pipeline and nature of service. Our major competitors in each region include:

North Louisiana: CenterPoint Energy Gas Marketing Company; Gulf South Pipeline L.P.; PanEnergy Louisiana Intrastate, LLC (Pelico).

East Texas: Enbridge Energy Partners LP.

South Texas: Enterprise Products Partners LP, Duke Energy Field Services, L.P.

West Texas: Southern Union Gas Services

Mid-Continent: Duke Energy Field Services, L.P.; ONEOK Energy Marketing and Trading, L.P.; Penn Virginia Corporation.

In transporting natural gas across north Louisiana, we face major competition from CenterPoint Energy Gas Marketing Company, Gulf South Pipeline, L.P., and Texas Gas Transmission, LLC.

RISK MANAGEMENT

To manage commodity price risk, we have implemented a risk management program under which we seek to match sales prices of commodities (especially natural gas) with purchases under our contracts; to manage our portfolio of contracts to reduce commodity price risk; to optimize our portfolio by active monitoring of basis, swing, and fractionation spread exposure; and to hedge a portion of our exposure to commodity prices.

To the extent that we purchase or commit contractually to purchase raw natural gas that we gather and process, we are exposed to commodity price changes in both the natural gas and NGL markets. Operationally, we mitigate this price risk by generally purchasing natural gas and NGLs at prices derived from published indices, rather than at a contractually fixed price and by marketing natural gas and natural gas liquids under similar pricing mechanisms. In addition, we optimize the operations of our processing facilities on a daily basis, for example by rejecting ethane in processing when recovery of ethane as an NGL is uneconomical.

As a consequence of our contract portfolio, we derive a portion of our earnings from a long position in NGL products, natural gas and condensate, resulting from the purchase of natural gas for our account or from the payment of processing charges in kind. This long position is exposed to commodity price fluctuations. We hedge this commodity price risk by purchasing a series of contracts relating to swaps of individual NGL, natural gas and crude oil products. Our hedging position and needs to supplement or modify our position are closely monitored by the Risk Management Committee of the Board of Directors of our Managing GP. Please read Item 7A-Quantitative and Qualitative Disclosures About Market Risk for information regarding the status of these contracts. As a matter of policy we do not acquire forward contracts or derivative products for the purpose of speculating on price changes.

REGULATION

Industry Regulation

Intrastate Pipeline Regulation. To the extent that our Regency Intrastate Pipeline system transports natural gas in interstate commerce, the rates, terms and conditions of that transportation service are subject to the jurisdiction of FERC, under Section 311 of the NGPA, which regulates, among other things, the provision of transportation services by an intrastate natural gas pipeline on behalf of an interstate natural gas pipeline. Under Section 311, rates charged for transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest. NGPA Section 311 rates deemed fair

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and equitable by FERC are generally analogous to the cost-based rates that FERC deems just and reasonable for interstate pipelines under the Natural Gas Act of 1938, or NGA. Certain aspects of FERC rate regulation under the NGA are discussed under the section below entitled Regulation Interstate Pipeline Regulation. Additionally, the terms and conditions of service set forth in the intrastate pipeline s Statement of Operating Conditions are subject to FERC approval.

FERC Pipeline Regulation. One of our subsidiaries, Regency Intrastate Gas LLC, or RIGS, transports interstate gas in Louisiana under Section 311(a)(2) of the NGPA for many of its shippers. FERC approves Section 311(a)(2) transportation rates for our intrastate pipeline (as for others) typically on a cost of service basis. FERC requires most of these pipelines, including RIGS, to file triennial rate petitions either justifying its existing rates or requesting new rates. RIGS most recent Section 311 maximum rates were established by a FERC order dated September 26, 2005 effective from May 1, 2005 to May 1, 2008, and were set for firm transportation at $0.15 per MMBtu reservation charge, with a $0.05 MMBtu commodity charge, and for interruptible transportation at $0.20 per MMBtu. RIGS is obligated to file its next Section 311 rate case no later than May 1, 2008.

Under Section 311 of the NGPA, intrastate pipelines providing transportation service under NGPA Section 311 are not subject to the provisions of the NGA that would otherwise apply. Any failure on our part:

- To observe the service limitations applicable to transportation service under Section 311,
- to comply with the rates approved by FERC for Section 311 service,
- to comply with the terms and conditions of service established in our FERC-approved Statement of Operating Conditions, or
- to comply with applicable FERC regulations, the NGPA or certain state laws and regulations

could result in an alteration of our jurisdictional status or the imposition of administrative, civil and criminal penalties, or both.

Our Regency Intrastate Pipeline system in north Louisiana is subject to regulation by various agencies of the State of Louisiana. Louisiana s Pipeline Operations Section of the Department of Natural Resources Office of Conservation is generally responsible for regulating intrastate pipelines and gathering facilities in Louisiana and has authority to review and authorize natural gas transportation transactions and the construction, acquisition, abandonment and interconnection of physical facilities. Historically, apart from pipeline safety, it has not acted to exercise this jurisdiction respecting gathering facilities. Louisiana also has agencies that regulate transportation rates, service terms and conditions and contract pricing to ensure their reasonableness and to ensure that the intrastate pipeline companies that they regulate do not discriminate among similarly situated customers.

Interstate Pipeline Regulation. FERC also has broad regulatory authority over the business and operations of interstate natural gas pipelines, such as the pipeline owned by our subsidiary Gulf States Transmission Corporation, or GSTC. Under the NGA, rates charged for interstate natural gas transmission must be just and reasonable, and amounts collected in excess of just and reasonable rates are subject to refund with interest. GSTC holds a FERC-approved tariff setting forth cost-based rates, terms and conditions for services to shippers wishing to take interstate transportation service. FERC s authority extends to:

- rates and charges for natural gas transportation and related services;
- certification and construction of new facilities;

extension or abandonment of services and facilities;

maintenance of accounts and records;

relationships between the pipeline and its energy affiliates;

terms and conditions of service;

depreciation and amortization policies;

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accounting rates for ratemaking purposes;

acquisition and disposition of facilities;

initiation and discontinuation of services; and

information posting requirements.

Gathering Pipeline Regulation. Section I(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC under the NGA. We own a number of natural gas pipelines that we believe meet the traditional tests FERC has used to establish a pipeline s status as a gatherer not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, on-going litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or the U.S. Congress.

State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and in some instances complaint-based rate regulation. We are subject to state ratable take and common purchaser statutes. The 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 that purchase gas 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 or one source of supply over another. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or gather natural gas.

Natural gas gathering may receive greater regulatory scrutiny at both the state and the federal levels now that FERC has taken a less stringent approach to regulation of the gas gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. For example, in 2006 the Texas Railroad Commission, or TRRC, approved changes to its regulations governing transportation and gathering services performed by intrastate pipelines and gatherers that prohibit such entities from unduly discriminating in favor of their affiliates. Also, the TRRC submitted to the Governor of Texas and the Texas Legislature its Texas Natural Gas Pipeline Competition Study Advisory Committee s report on competition in the gas pipeline industry. This study recommends, among other things, that the Texas Legislature give the TRRC certain expanded authority over gas pipelines, including specific authority to enforce its statutory duty to prevent discrimination in natural gas gathering and transportation, authority to enforce the requirement that parties participate in an informal complaint process, and authority to punish purchasers, transporters, and gatherers for retaliating against shippers and sellers in connection with such process. We have no way of knowing what portions of this study, if any, will be adopted by the Texas Legislature and implemented by the TRRC. We cannot predict what effect, if any, the proposed changes, if implemented, might have on our operations.

In addition, many of the producing states have adopted some form of complaint-based regulation that generally 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. 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 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 may be 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. The prices at which we sell natural gas are affected by many competitive factors, including 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. FERC is continually proposing and implementing new rules and regulations affecting interstate

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transportation, including interstate natural gas pipelines and natural gas storage facilities. 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. We do not believe that we will be affected by any such FERC action in a manner materially differently than other natural gas companies with whom we compete.

Oil Price Controls and Transportation Rates. Sales of crude oil, condensate and NGLs are not currently regulated. Prices of these products are set by the market rather than by regulation. Effective as of January 1, 1995, FERC implemented regulations establishing an indexing system for transportation rates for oil, NGLs and other products that allowed for an increase in the cost of transporting oil to the purchaser. The implementation of these regulations has not had a material adverse effect on our results of operations.

Regulatory Environment. In August 2005, Congress enacted and the President signed the Energy Policy Act of 2005. With respect to the oil and gas industry, the legislation focuses on the exploration and production sector, interstate pipelines, and refinery facilities. In many cases, the Act requires future action by various government agencies. We are unable to predict what impact, if any, the Act will have on our business, financial condition, results of operations or cash flows.

Texas Tax Legislation. In May 2006, the State of Texas passed legislation that imposes a margin tax on partnerships. We currently estimate that this legislation will not have a material effect on our business, financial condition, results of operations or cash flows.

Environmental Matters

General. Our operation of processing plants, pipelines and associated facilities, including compression, in connection with the gathering and processing of natural gas and the transportation of NGLs is subject to stringent and complex federal, state and local laws and regulations, including those governing, among other things, air emissions, wastewater discharges, the use, management and disposal of hazardous and nonhazardous materials and wastes, and the cleanup of contamination. Noncompliance with such laws and regulations, or incidents resulting in environmental releases, could cause us to incur substantial costs, penalties, fines and other criminal sanctions, third party claims for personal injury or property damage, investments to retrofit or upgrade our facilities and programs, or curtailment of operations. As with the industry generally, compliance with existing and anticipated environmental laws and regulations increases our overall costs of doing business, including our cost of planning, constructing and operating our plants, pipelines and other facilities. Included in our construction and operation costs are capital cost items necessary to maintain or upgrade our equipment and facilities to remain in compliance with environmental laws and regulations.

We have implemented procedures to ensure that all governmental environmental approvals for both existing operations and those under construction are updated as circumstances require. We believe that our operations and facilities are in substantial compliance with applicable environmental laws and regulations and that the cost of compliance with such laws and regulations will not have a material adverse effect on our business, results of operations and financial condition.

Under an omnibus agreement, Regency Acquisition LP, the entity that owns our Managing GP and our General Partner, agreed to indemnify us in an aggregate amount not to exceed $8,600,000, generally for three years after February 3, 2006, for certain environmental noncompliance and remediation liabilities associated with the assets transferred to us and occurring or existing before that date. For a discussion of the omnibus agreement, please read Item 13 Certain Relationships and Related Transactions, and Director Independence Omnibus Agreement.

Hazardous Substances and Waste Materials. To a large extent, the environmental laws and regulations affecting our operations relate to the release of hazardous substances and waste materials into soils, groundwater and surface water and include measures to control contamination of the environment. These laws and regulations generally regulate the generation, storage, treatment, transportation and disposal of hazardous substances and waste materials and may require investigatory and remedial actions at sites where such material has been released or disposed. For example, the Comprehensive Environmental Response, Compensation and

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Liability Act, or CERCLA, also known as the Superfund law, and comparable state laws, impose liability without regard to fault or the legality of the original conduct on certain classes of persons that contributed to a release of a hazardous substance into the environment. These persons include the owner and operator of the site where a release occurred and companies that disposed or arranged for the disposal of the hazardous substance that has been released into the environment. Under CERCLA, these persons may be subject to joint and several liability, without regard to fault, for, among other things, the costs of investigating and remediating the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA and comparable state law also authorize the federal Environmental Protection Agency, or EPA, its state counterparts, and, in some instances, 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. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Although petroleum as well as natural gas and NGLs are excluded from CERCLA s definition of a hazardous substance, in the course of our ordinary operations we generate wastes that may fall within that definition, and certain state law analogs to CERCLA, including the Texas Solid Waste Disposal Act, do not contain a similar exclusion for petroleum. We may be responsible under CERCLA or state laws for all or part of the costs required to clean up sites at which such substances or wastes have been disposed. We have not received any notification that we may be potentially responsible for cleanup costs under CERCLA or comparable state laws.

We also generate both hazardous and nonhazardous wastes that are subject to requirements of the federal Resource Conservation and Recovery Act, or RCRA, and comparable state statutes. From time to time, the EPA has considered the adoption of stricter handling, storage, and disposal standards for nonhazardous wastes, including crude oil and natural gas wastes. We are not currently required to comply with a substantial portion of the RCRA requirements at many of our facilities because the minimal quantities of hazardous wastes generated there make us subject to less stringent management standards. It is possible, however, that some wastes generated by us that are currently classified as nonhazardous may in the future be designated as hazardous wastes, resulting in the wastes being subject to more rigorous and costly disposal requirements, or that the full complement of RCRA standards could be applied to facilities that generate lesser amounts of hazardous waste. Changes in applicable regulations may result in a material increase in our capital expenditures or plant operating and maintenance expense.

We currently own or lease sites that have been used over the years by prior owners and by us for natural gas gathering, processing and transportation. Solid waste disposal practices within the midstream gas industry have improved over the years with the passage and implementation of various environmental laws and regulations. Nevertheless, some hydrocarbons and wastes have been disposed of or released on or under various sites during the operating history of those facilities that are now owned or leased by us. Notwithstanding the possibility that these dispositions may have occurred during the ownership of these assets by others, these sites may be subject to CERCLA, RCRA and comparable state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or contamination (including soil and groundwater contamination) or to prevent the migration of contamination.

Assets Acquired from El Paso. Under the agreement pursuant to which our operating partnership acquired assets from El Paso Field Services LP and its affiliates in 2003, we are indemnified for certain environmental matters. Those provisions include an indemnity by the El Paso sellers against a variety of environmental claims for a period of five years up to an aggregate of $84,000,000. The agreement also included an escrow of $9,000,000 relating to claims, including environmental claims.

In response to our submission of a claim to the El Paso sellers for a variety of environmental defects at these assets, the El Paso sellers have agreed to maintain $5,400,000 in the escrow account to pay any claims for environmental matters ultimately deemed to be covered by their indemnity. This amount represents the upper end of the estimated remediation cost calculated by Regency based on the results of its investigations of these assets.

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Since the time of this agreement, a Final Site Investigation Report has been prepared. Based on this additional investigation, environmental issues exist with respect to four facilities, including the two subject to accepted claims and two of our processing plants. The estimated remediation costs associated with the processing plants aggregate $2,750,000. We believe that any of our obligations to remediate the properties is subject to the indemnity under the El Paso PSA, and we intend to reinstate the claims for indemnification for these plant sites.

West Texas Assets. A Phase I environmental study was performed on our west Texas assets in connection with our investigation of those assets prior to our purchase of them in 2004. Most of the identified environmental contamination had either been remediated or was being remediated by the previous owners or operators of the properties. We believe that the likelihood that we will be liable for any significant potential remediation liabilities identified in the study is remote.

At the time of the negotiation of the agreement to acquire the west Texas assets, management of Regency Gas Services obtained an insurance policy against specified risks of environmental claims (other than those items known to exist). The policy covers clean-up costs and damages to third parties, and has a 10-year term (expiring 2014) with a $10,000,000 limit subject to certain deductibles.

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 plants, 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 to result in the increase of existing air emissions, that we obtain and strictly comply with air permits containing various emissions and operational limitations, or that we utilize specific emission control technologies to limit emissions. 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. In addition, our processing plants, pipelines and compression facilities are becoming subject to increasingly stringent regulations, including regulations that require the installation of control technology or the implementation of work practices to control hazardous air pollutants. Moreover, the Clean Air Act requires an operating permit for major sources of emissions and this requirement applies to some of our facilities. We believe that our operations are in substantial compliance with the federal Clean Air Act and comparable state laws.

ODEQ Notice of Violation. In March 2005, the Oklahoma Department of Environmental Quality, or ODEQ, sent us a notice of violation, alleging that we are operating the Mocane processing plant in Beaver County, Oklahoma in violation of the National Emission Standard for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities, or NESHAP, and the requirements to apply for and obtain a federal operating permit (Title V permit). After seeking and obtaining advice from the Environmental Protection Agency, the ODEQ issued an order requiring us to apply for a Title V permit with respect to emissions from the Mocane processing plant. While we believe that the basis for the allegations identified in the notice of violation is inapplicable to the Mocane processing plant, we have complied with the order. No fine or penalty was imposed by the ODEQ and the matter was fully resolved in June 2006.

TCEQ Notice of Enforcement. In November 2004, the Texas Commission on Environmental Quality, or TCEQ, sent us a notice of enforcement, or NOE, relating to the air emissions at the Waha processing plant in 2001 before it was acquired by us. We settled this NOE with the TCEQ in November 2005 for an immaterial amount.

Regardless of the allegations in the NOE, the air emissions at the Waha processing plant would have been considered grandfathered; and therefore not subject to more stringent emission limitations, only until 2007. In anticipation of the expiration of the facility s grandfathered status and regardless of the outcome of the NOE, in February 2005 we submitted an application to the TCEQ for a state air permit for the Waha plant predicated on the use of acid gas reinjection for air emission control and, after completion of the well and facilities, the reinjection of the previously emitted gases. The well was completed in March 2007 pursuant to an extension granted by the TCEQ.

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Clean Water Act. The Federal Water Pollution Control Act of 1972, as renamed and amended as the Clean Water Act, and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including natural gas liquid-related wastes, into waters of the United States. Pursuant to the Clean Water Act and similar state laws, a National Pollutant Discharge Elimination System, or NPDES, or state permit, or both, must be obtained to discharge pollutants into federal and state waters. The Clean Water Act and comparable state laws and their respective regulations provide for administrative, civil and criminal penalties for discharges of unauthorized pollutants into the water and also provide for penalties and liability for the costs of removing spills from such waters. In addition, the Clean Water Act and comparable state laws require that individual permits or coverage under general permits be obtained by subject facilities for discharges of storm water runoff. We believe that we are in substantial compliance with Clean Water Act permitting requirements as well as the conditions imposed thereunder, and that our continued compliance with such existing permit conditions will not have a material adverse effect on our business, financial condition, or results of operations.

Endangered Species Act. The Endangered Species Act restricts activities that may affect endangered or threatened species or their habitat. While we have no reason to believe that we operate in any area that is currently designated as a habitat for endangered or threatened species, the discovery of previously unidentified endangered species could cause us to incur additional costs or to become subject to operating restrictions or bans in the affected areas.

Employee Health and Safety. We are subject to the requirements of the federal Occupational Safety and Health Act, referred to as OSHA, and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements, including general industry standards, recordkeeping requirements, and monitoring of occupational exposure to regulated substances.

Safety Regulations. Those pipelines through which we transport mixed NGLs (exclusively to other NGL pipelines) are subject to regulation by the U.S. Department of Transportation, or DOT, under the Hazardous Liquid Pipeline Safety Act, or HLPSA, relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. The HLPSA requires any entity that owns or operates liquids pipelines to comply with the regulations under the HLPSA, to permit access to and allow copying of records and to submit certain reports and provide other information as required by the Secretary of Transportation. We believe our liquids pipelines are in substantial compliance with applicable HLPSA requirements.

Our intrastate pipeline facilities are subject to regulation by the DOT under the Natural Gas Pipeline Safety Act of 1968, as amended, or the NGPSA, and the Pipeline Safety Improvement Act of 2002, as amended, pursuant to which the DOT has established requirements relating to the design, installation, testing, construction, operation, inspection, replacement and management of pipeline facilities. The NGPSA covers natural gas, crude oil, carbon dioxide, NGL and petroleum products pipelines 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 submit certain reports and provide other information as required by the Secretary of Transportation. We believe that our pipeline operations are in substantial compliance with applicable NGPSA requirements.

Louisiana administers federal pipeline safety standards under the NGPSA. The Louisiana Office of Conservation, Pipeline Division, monitors Louisiana intrastate pipeline operators to ensure safety and compliance with regulations. Among other things, the Louisiana Office of Conservation conducts pipeline inspections and accident investigations, and it oversees compliance and enforcement, safety programs, and record maintenance and reporting. The rural gathering exemption under the NGPSA currently exempts our gathering facilities from jurisdiction under that statute.

The rural gathering exemption, however, may be restricted in the future, and that exemption does not apply to our intrastate natural gas pipeline facilities. With respect to recent pipeline accidents in other parts of the country, Congress and the DOT have passed or are considering heightened pipeline safety requirements, but such requirements, if adopted, would not be expected to affect us disproportionately relative to other companies in our industry. We believe, based on current information, that any costs that we may incur relating to environmental matters will not adversely affect us. We cannot be certain, however, that identification of presently unidentified conditions, more vigorous enforcement by regulatory agencies, enactment of more stringent laws and regulations, or other unanticipated events will not arise in the future and give rise to material environmental liabilities that could have a material adverse effect on our business, financial condition or results of operations.

EMPLOYEES

Our Managing GP and its affiliates employ 284 employees, of whom 201 are field operating employees and 83 are mid-and senior-level management and staff. None of these employees is represented by a labor union and there are no outstanding collective bargaining agreements to which our Managing GP or any of its affiliates is a party. Our Managing GP believes that it has good relations with its employees.

AVAILABLE INFORMATION

The Partnership files annual and quarterly financial reports, as well as interim updates of a material nature to investors with the Securities and Exchange Commission. You may read and copy any of these materials at the SEC s Public Reference Room at 100 F. Street, NE, Room 1580, Washington, DC 20549. Information on the operation of the Public Reference Room is available by calling the SEC at 1-800-SEC-0330. Alternatively, the SEC maintains an Internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. The address of that site is http://www.sec.gov.

The Partnership makes its SEC filings available to the public, free of charge and as soon as practicable after they are filed with the SEC, through its Internet site located at http://www.regencyenergy.com. Our annual reports are filed on Form 10-K, our quarterly reports are filed on Form 10-Q, and current-event reports are filed on Form 8-K and amendments to reports filed or furnished pursuant to Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934.

ITEM 1A. ***Risk Factors***

RISKS RELATED TO OUR BUSINESS

We may be unable to successfully integrate the operations of future acquisitions with our operations and we may not realize all the anticipated benefits of the acquisition of TexStar or any future acquisition.

Integration of TexStar with our business and operations has been a complex, time consuming and costly process. Failure to integrate TexStar successfully with our business and operations in a timely manner may have a material adverse effect on our business, financial condition and results of operations. We cannot assure you that we will achieve the desired profitability from TexStar or any other acquisitions we may complete in the future. In addition, failure to assimilate future acquisitions successfully could adversely affect our financial condition and results of operations.

Our acquisitions involve numerous risks, including:

- operating a significantly larger combined organization and adding operations;

difficulties in the assimilation of the assets and operations of the acquired businesses, especially if the assets acquired are in a new business segment or geographic area;

the risk that natural gas reserves expected to support the acquired assets may not be of the anticipated magnitude or may not be developed as anticipated;

the loss of significant producers or markets or key employees from the acquired businesses;

the diversion of management s attention from other business concerns;

the failure to realize expected profitability or growth;

the failure to realize expected synergies and cost savings;

coordinating geographically disparate organizations, systems and facilities; and

coordinating or consolidating corporate and administrative functions.

Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. If we consummate any future acquisition, our capitalization and results of operation may change significantly, and you may not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in evaluating future acquisitions.

While substantial amounts of the transportation capacity of the Regency Intrastate Pipeline System are subject to firm transportation contracts, if we are unable to utilize the remaining transportation capacity, our business and our operating results could be adversely affected.

As of March 1, 2007, we had definitive agreements for 562,900 MMBtu/d of firm transportation on the Regency Intrastate Pipeline System, of which 500,679 MMBtu/d was utilized in February 2007. During the month of February 2007, we also provided 195,395 MMBtu/d of interruptible transportation. If we are unable to commit the remaining uncommitted capacity on the system to firm gas transportation contracts and the parties to existing interruptible transportation contracts fail to utilize the capacity, our business and operating results could be adversely affected.

Because of the natural decline in production from existing wells, our success depends on our ability to obtain new supplies of natural gas, which involves factors beyond our control. Any decrease in supplies of natural gas in our areas of operation could adversely affect our business and operating results.

Our gathering and transportation pipeline systems are dependent on the level of production from natural gas wells that supply our systems and from which production will naturally decline over time. As a result, our cash flows associated with these wells will also decline over time. In order to maintain or increase through-put volume levels on our gathering and transportation pipeline systems and the asset utilization rates at our natural gas processing plants, we must continually obtain new supplies. The primary factors affecting our ability to obtain new supplies of natural gas and attract new customers to our assets are: the level of successful drilling activity near these systems and our ability to compete with other gathering and processing companies for volumes from successful new wells.

The level of natural gas drilling activity is dependent on economic and business factors beyond our control. The primary factor that impacts drilling decisions is natural gas prices. Natural gas prices reached historic highs in 2005 and early 2006 but have declined substantially in the second half of 2006. The averages of the NYMEX daily settlement prices per MMBtu of natural gas for the year ended December 31, 2005 and 2006 were $9.02 per MMBtu and $6.98 per MMBtu, respectively. A sustained decline in natural gas prices could result in a decrease in exploration and development activities in the fields served by our gathering and processing facilities and pipeline transportation systems, which would lead to reduced utilization of these assets. Other factors that impact production decisions include producers capital budget limitations, the ability of producers to obtain necessary drilling and other governmental permits and regulatory changes. Because of these factors, even if additional natural gas reserves were discovered in areas served by our assets, producers may choose not to develop those reserves. If we were not able to obtain new supplies of natural gas to replace the natural decline in volumes from existing wells due to reductions in drilling activity or competition, through-put volumes on our pipelines and the utilization rates of our processing facilities would decline, which could have a material adverse effect on our business, results of operations and financial condition.

We depend on certain key producers and other customers for a significant portion of our supply of natural gas. The loss of, or reduction in volumes from, any of these key producers or customers could adversely affect our business and operating results.

We rely on a limited number of producers and other customers for a significant portion of our natural gas supplies. Three customers represented 44 percent of our natural gas supply in our transportation segment for the year ended December 31, 2006. These contracts have terms that are range from month-to-month to life of lease. As these contracts expire, we will have to negotiate extensions or renewals or replace the contracts with those of other suppliers. For example, a significant contract with ExxonMobil expired in August 2006 and was not renewed. We may be unable to obtain new or renewed contracts on favorable terms, if at all. The loss of all or even a portion of the volumes of natural gas supplied by these producers and other customers, as a result of competition or otherwise, could have a material adverse effect on our business, results of operations and financial condition.

In accordance with industry practice, we do not obtain independent evaluations of natural gas reserves dedicated to our gathering systems. Accordingly, volumes of natural gas gathered on our gathering systems in the future could be less than we anticipate, which could adversely affect our business and operating results.

In accordance with industry practice, we 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 lives of such reserves. If the total reserves or estimated lives 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 could have an adverse effect on our business, results of operations and financial condition.

Natural gas, NGLs and other commodity prices are volatile, and a reduction in these prices could adversely affect our cash flow and operating results.

We are subject to risks due to frequent and often substantial fluctuations in commodity prices. NGL prices generally fluctuate on a basis that correlates to fluctuations in crude oil prices. In the past, the prices of natural gas and crude oil have been extremely volatile, and we expect this volatility to continue. For example, natural gas prices reached historic highs in 2005 and early 2006, but declined substantially in the second half of 2006. The NYMEX daily settlement price for natural gas for the prompt month contract in 2005 ranged from a high of $15.38 per MMBtu to a low of $5.79 per MMBtu and for the year ended December 31, 2006 ranged from a high of $10.63 per MMBtu to a low of $4.20 per MMBtu. The NYMEX daily settlement price for crude oil for the prompt month contract in 2005 ranged from a high of $69.81 per barrel to a low of $42.12 per barrel and for the year ended December 31, 2006 ranged from a high of $77.03 per barrel to a low of $55.81 per barrel. 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.

Our natural gas gathering and processing businesses operate under two types of contractual arrangements that expose our cash flows to increases and decreases in the price of natural gas and NGLs: percentage-of-proceeds and keep-whole arrangements. Under percentage-of-proceeds arrangements, we generally purchase natural gas from producers and retain an agreed percentage of the proceeds (in cash or in-kind) from the sale at market prices of pipeline-quality gas and NGLs or NGL products resulting from our processing activities. Under keep-whole arrangements, we receive the NGLs removed from the natural gas during our processing operations as the fee for providing our services in exchange for replacing the thermal content removed as NGLs with a like thermal content in pipeline-quality gas or its cash equivalent. Under these types of arrangements our revenues and our cash flows increase or decrease as the prices of natural gas and NGLs fluctuate. The relationship between natural gas prices and NGL prices may also affect our profitability. When natural gas prices are low relative to NGL prices, it is more profitable for us to process natural gas under keep-whole arrangements. When natural gas prices are high relative to NGL prices, it is less profitable for us and our customers to process natural gas both because of the higher value of natural gas and of the increased cost (principally that of natural gas as a feedstock and a fuel) of separating the mixed NGLs from the natural gas. As a result, we may experience periods in which higher natural gas prices relative to NGL prices reduce our processing margins or reduce the volume of natural gas processed at some of our plants. For a detailed discussion of these arrangements, please read Item 1 Business Our Contracts.

In our gathering and processing operations, we purchase raw natural gas containing significant quantities of NGLs, process the raw natural gas and sell the processed gas and NGLs. If we are unsuccessful in balancing the purchase of raw natural gas with its component NGLs and our sales of pipeline quality gas and NGLs, our exposure to commodity price risks will increase.

We purchase from producers and other customers a substantial amount of the natural gas that flows through our natural gas gathering and processing systems and our transportation pipeline for resale to third parties, including natural gas marketers and utilities. We may not be successful in balancing our purchases and sales. In addition, a producer could fail to deliver promised volumes or could deliver volumes in excess of contracted volumes, a purchaser could purchase less than contracted volumes, or the natural gas price differential between the regions in which we operate could vary unexpectedly. 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 results.

Our results of operations and cash flow may be adversely affected by risks associated with our hedging activities.

In performing our functions in the Gathering and Processing segment, we are a seller of NGLs and are exposed to commodity price risk associated with downward movements in NGL prices. As a result of the volatility of NGLs, we have executed swap contracts settled against ethane, propane, butane, natural gasoline and west Texas intermediate crude market prices, supplemented with crude oil put options. (Historically, changes in the prices of heavy NGLs, such as natural gasoline, have generally correlated with changes in the price of crude oil.) The Partnership has executed swap contracts settled against ethane, propane, butane, natural gasoline, crude oil and natural gas market prices. As of March 29, 2007, we have hedged approximately 71 percent of our expected exposure to NGL in 2007 and 2008 and approximately 28 percent in 2009. We have hedged approximately 66 percent of our expected exposure to condensate prices in 2007 and approximately 64 percent in 2008 and 2009. We have hedged approximately 60 percent of our expected exposure to natural gas prices in 2007. We continually monitor our hedging and contract portfolio and expect to continue to adjust our hedge position as conditions warrant. Also, we may seek to limit our exposure to changes in interest rates by using financial derivative instruments and other hedging mechanisms from time to time. For more information about our risk management activities, please read Item 7A Quantitative and Qualitative Disclosures about Market Risk.

Even though our management monitors our hedging activities, these activities can result in substantial losses. Such losses could occur under various circumstances, including any circumstance in which a counterparty does not perform its obligations under the applicable hedging arrangement, the hedging arrangement is imperfect, or our hedging policies and procedures are not followed or do not work as planned.

To the extent that we intend to grow internally through construction of new, or modification of existing, facilities, we may not be able to manage that growth effectively, which could decrease our cash flow and adversely affect our results of operation.

A principal focus of our strategy is to continue to grow by expanding our business both internally and through acquisitions. Our ability to grow internally will depend on a number of factors, some of which will be beyond our control. In general, 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. Any project that we undertake may not be completed on schedule, at budgeted cost or at all. Construction may occur over an extended period, and we are not likely to receive a material increase in revenues related to such project until it is completed. Moreover, our revenues may not increase immediately upon its completion because the anticipated growth in gas production that the project was intended to capture does not materialize, our estimates of the growth in production prove inaccurate or for other reasons. For any of these reasons, newly constructed or modified midstream facilities may not generate our expected investment return and that, in turn, could adversely affect our cash flows and results of operations.

In addition, our ability to undertake to grow in this fashion will depend on our ability to finance the construction or modification project and on our ability to hire, train and retain qualified personnel to manage and operate these facilities when completed.

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

Since we will distribute all of our available cash to our unitholders, subject to the limitations on restricted payments contained in the indenture governing our senior notes and our credit facility, we will depend on financing provided by commercial banks and other lenders and the issuance of debt and equity securities to finance any significant internal organic growth or acquisitions. For a definition of available cash, please see our partnership agreement. If we are unable to obtain adequate financing from these sources, our ability to grow will be limited.

Our industry is highly competitive, and increased competitive pressure could adversely affect our business and operating results.

We compete with similar enterprises in each of our areas of operations. Some of our competitors are large oil, natural gas and petrochemical companies that have greater financial resources and access to supplies of natural gas than we do. In addition, our customers who are significant producers or consumers of NGLs may develop their own processing facilities in lieu of using ours. Similarly, competitors may establish new connections with pipeline systems that would create additional competition for services that we provide to our customers. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of our competitors. All of these competitive pressures could have a material adverse effect on our business, results of operations and financial condition.

If third-party pipelines interconnected to our processing plants become unavailable to transport NGLs, our cash flow and results of operations could be adversely affected.

We depend upon third party pipelines that provide delivery options to and from our processing plants for the benefit of our customers. If any of these pipelines become unavailable to transport the NGLs produced at our related processing plants, we would be required to find alternative means to transport the NGLs out of our

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processing plants, which could increase our costs, reduce the revenues we might obtain from the sale of NGLs or reduce our ability to process natural gas at these plants.

We are exposed to the credit risks of our key customers, and any material nonpayment or nonperformance by our key customers could adversely affect our cash flow and results of operations.

We are subject to risks of loss resulting from nonpayment or nonperformance by our customers. Any material nonpayment or nonperformance 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 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, processing and transportation of natural gas and NGLs, including:

- damage to our gathering and processing facilities, 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 pipelines, measurement equipment or facilities at receipt or delivery points;
- fires and explosions;
- weather related hazards, such as hurricanes; and
- other hazards, including those associated with high-sulfur content, or sour gas, such as an accidental discharge of hydrogen sulfide 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 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 insured against all environmental events that might occur. If a significant accident or event occurs that is not insured or fully insured, it could adversely affect our operations and financial condition.

Due to our lack of asset diversification, adverse developments in our midstream operations would adversely affect our cash flows and results of operations.

We rely exclusively on the revenues generated from our midstream energy business, 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 this business would have a significantly greater impact on our financial condition and results of operations than if we maintained more diverse assets.

Failure of the gas that we ship on our pipelines to meet the specifications of interconnecting interstate pipelines could result in curtailments by the interstate pipelines.

The markets to which the shippers on our pipelines ship natural gas include interstate pipelines. These interstate pipelines establish specifications for the natural gas that they are willing to accept, which include requirements such as hydrocarbon dewpoint, temperature, and foreign content including water, sulfur, carbon dioxide and hydrogen sulfide. These specifications vary by interstate pipeline. If the total mix of natural gas shipped by the shippers on our pipeline fails to meet the specifications of a particular interstate pipeline, it may refuse to accept all or a part of the natural gas scheduled for delivery to it. In those circumstances, we may be required to find alternative markets for that gas or to shut-in the producers of the non-conforming gas, potentially reducing our through-put volumes or revenues. Please see Item 1 Business.

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Terrorist attacks, the threat of terrorist attacks, 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 magnitude of the threat of future terrorist attacks on the energy transportation industry in general and on us in particular are not known at this time. Uncertainty surrounding continued hostilities in the Middle East or other sustained military campaigns may affect our operations in unpredictable ways, including disruptions of natural gas supplies and markets for natural gas and NGLs 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.

We do not own all of the land on which our pipelines and facilities have been constructed, and we are therefore subject to the possibility of increased costs or the inability to retain necessary land use.

We obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies for specified periods of time. Many of these rights-of-way are perpetual in duration; others have terms ranging from five to ten years. Many are subject to rights of reversion in the case of non-utilization for periods ranging from one to three years. In addition, some of our processing facilities are located on leased premises. Our loss of these rights, through our inability to renew right-of-way contracts or leases or otherwise, could have a material adverse effect on our business, results of operations and financial condition.

In addition, 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 to capitalize on other attractive expansion opportunities. If the cost of obtaining new rights-of-way increases, then our cash flows and growth opportunities could be adversely affected.

A successful challenge to the rates we charge on our Regency Intrastate Pipeline may reduce the amount of cash we generate.

To the extent our Regency Intrastate Pipeline transports natural gas in interstate commerce, the rates, terms and conditions of that transportation service are subject to regulation by the FERC, pursuant to Section 311 of the NGPA, which regulates, among other things, the provision of transportation services by an intrastate natural gas pipeline on behalf of an interstate natural gas pipeline. Under Section 311, rates charged for transportation must be fair and equitable, and the FERC is required to approve the terms and conditions of the service. Rates established pursuant to Section 311 are generally analogous to the cost based rates FERC deems just and reasonable for interstate pipelines under the NGA. FERC may therefore apply its NGA policies to determine costs that can be included in cost of service used to establish Section 311 rates. These rate policies include the recent FERC policy on income tax allowance that permits interstate pipelines to include, as part of the cost of service, a full income tax allowance for all entities owning the utility asset provided such entities or individuals are subject to an actual or potential tax liability. If the Section 311 rates presently approved for Regency through May 1, 2008 are successfully challenged in a complaint or after such date the FERC disallows the inclusion of costs in the cost of service, changes its regulations or policies, or establishes more onerous terms and conditions applicable to Section 311 service, this may adversely affect our business. Any reduction in our rates could have an adverse effect on our business, results of operations and financial condition.

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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.

Our natural gas gathering and intrastate transportation operations are generally exempt from FERC regulation under the NGA, but FERC regulation still affects these businesses and the markets for products derived from these businesses. FERC s policies and practices, 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 regulatory policies. We cannot assure you, however, 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 at FERC and in the courts and of policy discussions at FERC, so, in such circumstances, the classification and regulation of some of our gathering facilities or our intrastate transportation pipeline may be subject to change based on future determinations by FERC, the courts or Congress. Such a change could result in increased regulation by FERC.

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, oil or 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 oil and natural gas gathering activities, which allows oil and natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to oil and natural gas gathering access and rate discrimination. Please read Item 1 Business Regulation.

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 governing, among other things, air emissions, wastewater discharges, the use, management and disposal of hazardous and nonhazardous materials and wastes, and the cleanup of contamination. Noncompliance with such laws and regulations, or incidents resulting in environmental releases, could cause us to incur substantial costs, penalties, fines and other criminal sanctions, third party claims for personal injury or property damage, investments to retrofit or upgrade our facilities and programs, or curtailment of operations. Certain environmental statutes, including CERCLA and comparable state laws, impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed or otherwise released.

There is inherent risk of the incurrence of environmental costs and liabilities in our business due to the necessity of handling natural gas and 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. We cannot be certain, however, that identification of presently unidentified conditions, more vigorous enforcement by regulatory agencies, enactment of more stringent laws and regulations, or other unanticipated events will not arise in the future and give rise to material environmental liabilities that could have a material adverse effect on our business, financial condition or results of operations. Please read Item 1 Business Regulation Environmental matters and Item 7 Management s

Discussion and Analysis of Financial Condition and Results of Operations Other Matters Environmental Matters.

If we fail to develop or maintain an effective system of internal controls, we may not be able to report our financial results accurately or prevent fraud.

We became subject to the public reporting requirements of the Securities Exchange Act of 1934 on February 3, 2006. We produce our consolidated financial statements in accordance with the requirements of GAAP, but we do not become subject to certain of the internal controls standards applicable to most companies with publicly traded securities until 2008. We may not currently meet all those standards. Effective internal controls are necessary for us to provide reliable financial reports to prevent fraud and to operate successfully as a publicly traded partnership. Our efforts to develop and maintain our internal controls compliance program may not be successful, and we may be unable to maintain adequate controls over our financial processes and reporting in the future, including compliance with the obligations under Section 404 of the Sarbanes-Oxley Act of 2002, which we refer to as Section 404. For example, Section 404 will require us, among other things, annually to review and report on, and our independent registered public accounting firm to attest to, our internal control over financial reporting. We must comply with Section 404 for our fiscal year ending December 31, 2007. Any failure to develop or maintain an effective internal controls compliance program or difficulties encountered in its implementation or other effective improvement of our internal controls could harm our operating results or cause us to fail to meet our reporting obligations. Given the difficulties inherent in the design and operation of internal controls over financial reporting, we can provide no assurance as to our conclusions under Section 404, or those of our independent registered public accounting firm, regarding the effectiveness of our internal controls. Ineffective internal controls subject us to regulatory scrutiny and a loss of confidence in our reported financial information, which could have an adverse effect on our business, results of operations and financial condition.

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets.

We are a holding company, and our subsidiaries conduct all of our operations and own all of our operating assets. We have no significant assets other than the partnership interests and the equity in our subsidiaries. As a result, our ability to make required payments on the senior notes depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, our credit facility and applicable state partnership and other laws and regulations. Pursuant to our credit facility, we may be required to establish cash reserves for the future payment of principal and interest on the amounts outstanding under our credit facility. If we are unable to obtain the funds necessary to pay the principal amount of the senior notes at maturity, we may be required to adopt one or more alternatives, such as a refinancing of the senior notes. We cannot assure you that we would be able to refinance the senior notes.

Our leverage may limit our ability to borrow additional funds, comply with the terms of our indebtedness or capitalize on business opportunities.

Our leverage is significant in relation to our partners capital. Our debt to capital ratio (calculated as total debt divided by the sum of total debt and partners capital) as of December 31, 2006 was 76 percent. As of March 22, 2007, our total outstanding long-term debt was $698,100,000. We will be prohibited from making cash distributions during an event of default under any of our indebtedness. Various limitations in our credit facility, as well as the indentures for the notes, may reduce our ability to incur additional debt, to engage in some transactions and to capitalize on business opportunities. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions.

Our leverage may adversely affect our ability to fund future working capital, capital expenditures and other general partnership requirements, future acquisition, construction or development activities, or to otherwise fully realize the value of our assets and opportunities because of the need to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness or to comply with any restrictive terms of our indebtedness. Our leverage may also make our results of operations more susceptible to adverse economic and industry conditions by limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate and may place us at a competitive disadvantage as compared to our competitors that have less debt.

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

During 2004 and 2005, the credit markets experienced 50-year record lows in interest rates. During the latter half of 2005 and in 2006, interest rates increased. If the overall economy continues to strengthen, monetary policy may tighten further, resulting in higher interest rates to counter possible inflation. The interest rate on our senior notes is fixed and the loans outstanding under our credit facility bear interest at a floating rate. An increase of 100 basis points in the LIBOR rate would increase our annual payment by $1,100,000. Additionally, 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, the market price for our units will be affected by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank 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 effect on our unit price and our ability to issue additional equity, in order to make acquisitions, to reduce debt or for other purposes.

You may not be able to sell large blocks of our common units in a single day without realizing a lower than expected sales price.

During the six months ended March 15, 2007, the average daily volume of our common units traded on the NASDAQ was 43,000. The median of the daily volume for the same period was 39,200. The maximum and minimum daily volume for the same period was 120,400 and 8,500, respectively. If we are unable to increase the market demand for our equity securities, you may be adversely affected.

We may not have the ability to raise funds necessary to finance any change of control offer required under our senior notes.

If a change of control (as defined in the indenture) occurs, we will be required to offer to purchase our outstanding senior notes at 101 percent of their principal amount plus accrued and unpaid interest. If a purchase offer obligation arises under the indenture governing the senior notes, a change of control could also have occurred under the senior secured credit facilities, which could result in the acceleration of the indebtedness outstanding thereunder. Any of our future debt agreements may contain similar restrictions and provisions. If a purchase offer were required under the indenture for our debt, we may not have sufficient funds to pay the purchase price of all debt that we are required to purchase or repay.

RISKS RELATED TO OUR STRUCTURE

HM Capital Investors own 60.2 percent of the limited partner units outstanding and control 100 percent of our general partner, which has sole responsibility for conducting our business and managing our operations.

HM Capital Investors own 60.2 percent of the limited partner units outstanding and control 100 percent of our general partner. Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to its owners, the HM Capital Investors. Conflicts of interest may arise between the HM Capital

Investors and their affiliates, including our general partner, on the one hand, and us,

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on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates over our interests. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires the HM Capital Investors or their affiliates to pursue a business strategy that favors us;
- our General Partner is allowed to take into account the interests of parties other than us, such as the HM Capital Investors, in resolving conflicts of interest;
- HM Capital Investors and their affiliates may engage in competition with us;
- 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 partnership securities, and reserves, each of which can affect the amount of cash available to pay interest on, and principal of, the notes;
- our General Partner determines which costs incurred by it and its affiliates are reimbursable by us;
- our partnership agreement does not restrict our General Partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- our General Partner intends to limit its liability regarding our contractual and other obligations; and
- our General Partner controls the enforcement of obligations owed to us by our General Partner and its affiliates.

HM Capital Investors and their affiliates may compete directly with us.

HM Capital Investors and their affiliates are not prohibited from owning assets or engaging in businesses that compete directly or independently with us. In addition, HM Capital Investors or their affiliates may acquire, construct or dispose of any additional midstream or other assets in the future, without any obligation to offer us the opportunity to purchase or construct or dispose of those assets.

Our reimbursement of our general partner s expenses will reduce our cash available for distribution to you.

Prior to making any distribution on the common units, we will reimburse our general partner and its affiliates for all expenses they incur on our behalf. These expenses will include all costs incurred by our general partner and its affiliates in managing and operating us, including costs for rendering corporate staff and support services to us. Please read Item 13. Certain Relationships and Related Party Transactions, and Directors Independence. The reimbursement of expenses of our general partner and its affiliates could adversely affect our ability to pay cash distributions to you.

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 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. Examples include the exercise of its limited call right, its voting rights with respect to the units it owns, its registration rights and its determination whether or not to consent to any merger or consolidation of the partnership;

provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith, meaning it believed the decision was in the best interests of our partnership;

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

provides generally that affiliated transactions and resolutions of conflicts of interest not approved by the conflicts committee of our general partner and not involving a vote of unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or be fair and reasonable to us, as determined by our general partner in good faith, and that, in determining whether a transaction or resolution is fair and reasonable, our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us; and

provides that our general partner and its officers and directors will not be liable for monetary damages to us, our 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.

By purchasing a common unit, a common unitholder will become bound by the provisions in the partnership agreement, including the provisions discussed above.

Unitholders have limited voting rights and are not entitled to elect our general partner or its directors.

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 its board of directors and will have no right to elect our general partner or its board of directors 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 will 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.

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

The unitholders are currently unable to remove the general partner without its consent because the general partner and its affiliates own sufficient units to be able to prevent its removal. The vote of the holders of at least 662/3 percent of all outstanding units voting together as a single class is required to remove the general partner. Our general partner and its affiliates own 60.2 percent of the total of our common and subordinated units. Moreover, if our general partner is removed without cause during the subordination period and units held by our 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.

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

Unitholders voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20 percent or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees, and persons who acquired such units with the prior approval of our general partner, cannot vote on any matter. Our partnership agreement also contains provisions limiting the

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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.

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 partners of our general partner from transferring their ownership in our general partner to a third party. The new partners of our general partner would then be in a position to replace the board of directors and officers of Regency GP LLC with their own choices and to control the decisions taken by the board of directors and officers.

We may issue an unlimited number of additional units without your approval, which would dilute your existing ownership interest.

Our general partner, without the approval of our unitholders, may cause us to issue an unlimited number of additional common units.

The issuance by us 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 will 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; and
- the market price of the common units may decline.

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 percent 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. Our general partner and its affiliates now own approximately 31.3 percent of the common units. At the end of the subordination period, assuming no additional issuances of common units, our general partner and its affiliates will own approximately 60.2 percent of the common units.

Your liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. In most states, a limited partner is only liable if he participates in the control of the business of the partnership. These statutes generally do not define control, but do permit limited partners to engage in certain activities, including, among other actions, taking any action with respect to the dissolution of the partnership, the sale, exchange, lease or mortgage of any asset of the partnership, the admission or removal of the general partner

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and the amendment of the partnership agreement. You could, however, 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 take other actions under our partnership agreement is found to 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 distribution, limited partners who received an impermissible distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable for the obligations of the assignor to make required contributions to the partnership other than contribution obligations that are unknown to the substituted limited partner at the time it became a limited partner and that could not be ascertained 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 RELATING TO OUR COMMON UNITS

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service, or IRS, treats us as a corporation or we become subject to a material amount of entity-level taxation for state tax purposes, it would substantially reduce the amount of cash available for payment for distributions on our common units.

Under Section 7704 of the Internal Revenue Code, a publicly traded partnership may be taxed as a corporation unless it satisfies a qualifying income exception that allows it to be treated as a partnership for U.S. federal income tax purposes. We believe that we meet the qualifying income exception and currently expect to meet such exception for the foreseeable future. If the IRS were to disagree and if we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35 percent, and would likely pay state income tax at varying rates. 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 the units.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. 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 ending in 2007. Specifically, the Texas margin tax will be imposed at a maximum effective rate of 0.7 percent of our gross income apportioned to Texas. Imposition of such a tax on us by Texas, or any other state, will reduce our cash flow.

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

We did not request 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 positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with all of the 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

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costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

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

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

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

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

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

Investment in common units by tax-exempt entities, such as individual retirement accounts (known as IRAs), other retirement plans and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs 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 regulated investment company, you should consult your tax advisor before investing in our common units.

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

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

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

In addition to federal income taxes, you will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property, even if you do not live in any of those jurisdictions. You will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, you may be subject to penalties for failure to comply with those requirements. We own assets and do business in Texas, Oklahoma, Kansas, Louisiana, and Colorado. Each of these states, other than Texas, currently imposes a personal income tax as well as an income tax on corporations and other entities. Texas imposes a franchise tax (which is based in part on net income) on corporations and limited liability companies. As we make acquisitions or expand our business, we may own assets or do business in additional states that impose a personal income tax. It is your responsibility to file all United States federal, foreign, state and local tax returns.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

Substantially all of our pipelines, which are located in Texas, Louisiana, Oklahoma, Kansas and, to a minor extent, Colorado, 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, easement agreements from public authorities and railroad companies to cross over or under, or to lay facilities in or along, watercourses, county roads, municipal streets, railroad properties and state highways, as applicable. In some cases, properties on which our pipelines were built were purchased in fee.

We believe that we have satisfactory title to all our assets. Record title to some of our assets may continue to be held by prior owners until we have made the appropriate filings in the jurisdictions in which such assets are located. Substantially all our assets are subject to either a security interest in favor of our senior notes or a first priority lien and security interest in favor of the lending banks under our credit facility. Title to our assets may also be subject to other encumbrances. We believe that none of such encumbrances should materially detract from the value of our properties or our interest in those properties or should materially interfere with our use of them in the operation of our business.

Office Facilities

Our executive offices occupy one entire floor in an office building at 1700 Pacific Avenue, Dallas, Texas, under a lease that expires at the end of October 2008. We also maintain small regional offices located on leased premises in Shreveport, Louisiana; Tulsa, Oklahoma; and Midland and San Antonio, Texas. We lease the San Antonio office space from BlackBrush Energy, Inc., a related party. 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. For additional information regarding our properties, please read Item 1 Business .

Item 3. ***Legal Proceedings***

The operations of our operating partnership, Regency Gas Services LP or RGS, and its subsidiaries are subject to a variety of risks and disputes normally incident to our business. As a result, we may, at any given time, be a defendant in various legal proceedings and litigation arising in the ordinary course of business. Neither the Partnership nor any of its subsidiaries, including RGS, is, however, currently a party to any pending or, to our knowledge, threatened material legal or governmental proceedings, including proceedings under any of the various environmental protection statutes to which it is subject. See, however, the discussion of the TCEQ NOE and the ODEQ NOV under Item 1 Business Environmental Matters TCEQ Notice of Enforcement and Item 1 Business Environmental Matters ODE Notice of Violation.

We maintain insurance policies with insurers in amounts and with coverage and deductibles that we, with the advice of our insurance advisors and brokers, believe are reasonable and prudent. We cannot, however, 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.

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Part II

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

Market Price of and Distributions on the Common Units and Related Unitholder Matters

Our common units were first offered and sold to the public on February 3, 2006. Our common units are listed on The Nasdaq Stock Market, LLC under the symbol RGNC . As of March 22, 2007, the number of holders of record of common units was 50, including Cede & Co., as nominee for Depository Trust Company, which held of record 15,099,963 common units. Additionally, there were 17 unitholders of record of our subordinated units. There is no established public trading market for our subordinated units. Following the announcement by The Nasdaq Stock Market LLC of different market tiers in February 2006, our common units were listed on the Nasdaq Global Market until March 2007 at which time The Nasdaq Stock Market LLC authorized an intermarket transfer of our common units to the Nasdaq Global Select Market. For more information on the status of our listing on the Nasdaq, see Item 10. Directors, Executive Officers and Corporate Governance Audit Committee. The following table sets forth, for the periods indicated, the high and low quarterly sales prices per common unit, as reported on The Nasdaq Stock Market, LLC, and the cash distributions declared per common unit.

Period	Price Range High	Price Range Low	Cash Distributions Declared (per unit)
2006			
First Quarter(1)	$ 22.10	$ 19.47	$
Second Quarter	23.00	21.30	0.2217
Third Quarter(2)	24.52	22.21	0.3500
Fourth Quarter(2)	27.20	24.75	0.3700
2007			
First Quarter (through March 22, 2007)	28.40	26.70	0.3700

(1) The distribution for the quarter ended March 31, 2006 reflects a pro rata portion of our $0.35 per unit minimum quarterly distribution, covering the period from the February 3, 2006 closing of our initial public offering through March 31, 2006.

(2) Represents the minimum quarterly distribution per common unit plus $0.02 per unit excluding the Class B and Class C common units which were not entitled to any distributions until after they were converted into common units. The Class B Units and the Class C Units converted into common units on a one-for-one basis on February 15, 2007 and February 8, 2007, respectively, and as such, will be entitled to future cash distributions.

Cash Distribution Policy

We distribute to our unitholders, on a quarterly basis, all of our available cash in the manner described below. During the subordination period (as defined in our partnership agreement), 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, or MQD, of $0.35 per quarter, plus any arrearages in the payment of the MQD on the common units from prior quarters, before any distributions of available cash may be made on the subordinated units. If we do not have sufficient cash to pay our distributions as well as satisfy our other operational and financial obligations, our General Partner has the ability to reduce or eliminate the distribution paid on our common units and subordinated units so that we may satisfy such obligations, including payments on our debt instruments.

Available cash generally means, for any quarter ending prior to liquidation, all cash on hand at the end of that quarter less the amount of cash reserves that are necessary or appropriate in the reasonable discretion of the General Partner to:

- provide for the proper conduct of our business;
- comply with applicable law or any partnership debt instrument or other agreement; or
- provide funds for distributions to unitholders and the general partner in respect of any one or more of the next four quarters.

In addition to distributions on its 2 percent General Partner interest, our General Partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in the following table.

	Total Quarterly Distribution Target Amount	Marginal Percentage Interest in Distributions	
		Unitholders	General Partner
Minimum Quarterly Distribution	$0.3500	98%	2%
First Target Distribution	up to $0.4025	98%	2%
Second Target Distribution	above $0.4025 up to $0.4375	85%	15%
Third Target Distribution	above $0.4375 up to $0.5250	75%	25%
Thereafter	above $0.5250	50%	50%

Under the terms of the agreements governing our debt, we are prohibited from declaring or paying any distribution to unitholders if a default or event of default (as defined in such agreements) exists. See Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Fourth Amended and Restated Credit Agreement and Senior Notes.

Recent Sales of Unregistered Securities

On September 8, 2005, in connection with our formation we issued (i) to our general partner, Regency GP LP, its 2 percent general partner interest in us for $20 and (ii) to Regency Acquisition LLC its 98 percent limited partner interest in us for $980. As an integral part of the reorganization of RGS in connection with our initial public offering, we issued (i) 5,353,896 common units and 19,103,896 subordinated units to Regency Acquisition LP, successor to Regency Acquisition LLC, in exchange for certain equity interests in RGS and its general partner and (ii) incentive distribution rights (which represent the right to receive increasing percentages of quarterly distributions in excess of specified amounts) to our general partner in exchange for certain member interests. On March 8, 2006, we closed the sale of an additional 1,400,000 common units at a price of $20 per unit as the underwriters exercised their over allotment option in part. The net proceeds from the sale were used by us to redeem an equivalent number of common units held by Regency Acquisition LP for the benefit of the HM Capital Investors. The common and subordinated units were distributed by Regency Acquisition LP to its parent partnership which then further distributed an aggregate of 457,871 common units and 2,212,279 subordinated units to two directors and seven officers of the Managing GP upon their exchange of certain equity interests in that partnership. The registrant claims exemption from the registration provisions of the Securities Act of 1933 under section 4(2) thereof for these issuances.

On August 15, 2006, in connection with the TexStar Acquisition, we issued 5,173,189 of Class B common units to HMTF Gas Partners II, LP (HMTF Gas Partners) as partial consideration for the TexStar acquisition. The Class B common units have the same terms and conditions as our common units, except that the Class B common units are not entitled to participate in distributions by the Partnership. The Class B common units were converted into common units without the payment of further consideration on a one-for-one basis on February 15, 2007. The registrant claims exemption from the registration provisions of the Securities Act of 1933 under section 4(2) thereof for these issuances.

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On September 21, 2006, we entered into a Class C Unit Purchase Agreement with certain purchasers, pursuant to which the purchasers purchased from us 2,857,143 Class C common units representing limited partner interests in the Partnership at a price of $21 per unit. The Class C common units have the same terms and conditions as the Partnership s common units, except that the Class C common units are not entitled to participate in distributions by the Partnership. The Class C common units were converted into common units without the payment of further consideration on a one-for-one basis on February 8, 2007. The registrant claims exemption from the registration provisions of the Securities Act of 1933 under section 4(2) thereof for these issuances.

There have been no other sales of unregistered equity securities during the last three years.

Use of Proceeds

In connection with the offering and sale by us of 13,750,000 common units on February 3, 2006 pursuant to our initial public offering of securities, we received net proceeds of $257,000,000, after deducting underwriting discounts, fees and commissions but before paying estimated offering expenses. We used the aggregate net proceeds of this offering:

To replenish $48,000,000 of the working capital, or 18 percent of the net proceeds, $37,000,000 of which was used to repay working capital borrowings under the revolving portion of our second amended and restated credit facility, that was distributed to the HM Capital Investors by RGS, immediately prior to consummation of the offering and the related formation transactions;

to distribute $195,757,000, or 76 percent of net proceeds, to the HM Capital Investors for reimbursement of capital expenditures comprising most of the initial investment by the HM Capital Investors in Regency Gas Services LLC;

to pay $9,000,000, or 4 percent of net proceeds, to an affiliate of HM Capital as consideration for the termination of ten-year financial advisory and monitoring and oversight agreements between the affiliate of HM Capital and us; and

to pay $4,500,000, or 2 percent of net proceeds, of expenses associated with the offering and related formation transactions.

The HM Capital Investors realized $243,500,000 as a result of distributions made by us in connection with the offering, including the $48,000,000 of working capital distributed to them immediately prior to the consummation of the offering. This represented approximately 94.7 percent of the net proceeds from the offering. In addition, an affiliate of HM Capital received $9,000,000 in connection with the termination of the financial advisory and monitoring and oversight agreements with us.

Borrowings under the revolving portion of our second amended and restated credit facility were incurred temporarily to finance working capital. Those borrowings under the revolving portion of our second amended and restated credit facility bore interest at the annual rate of 8.5 percent and would otherwise have matured on June 1, 2010. Affiliates of UBS Securities LLC, Wachovia Capital Markets, LLC and KeyBanc Capital Markets, a Division of McDonald Investments Inc., are lenders under our second amended and restated credit facility.

In early March, the underwriters of our initial public offering exercised in part their option to purchase additional common units pursuant to the underwriting agreement by purchasing 1,400,000 common units for $28,000,000 ($26,200,000 net to the Partnership). On March 8, 2006, we closed the sale of the additional 1,400,000 common units at a price of $20 per unit as the underwriters exercised their over allotment option in part. The net proceeds from the sale were used by us to redeem an equivalent number of common units held by Regency Acquisition LP for the benefit of the HM Capital Investors.

In connection with the TexStar acquisition on August 15, 2006, we issued 5,173,189 of Class B common units to HTMF Gas Partners, an affiliate of HM Capital. In addition, we made a cash payment of $62,074,000 and assumed $167,652,000 of TexStar s outstanding bank debt, subject to working capital adjustments.

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In connection with the sale of 2,857,143 Class C common units on September 21, 2006, we received net proceeds of $59,942,000, after deducting issuance costs. We used the net proceeds to reduce amounts outstanding under our credit facility.

Item 6. ***Selected Financial Data***

The historical financial information presented below for the Partnership and our predecessors, Regency LLC Predecessor and Regency Gas Services LP (formerly Regency Gas Services LLC), was derived from our audited consolidated financial statements as of December 31, 2006, 2005 and 2004 and for the years ended December 31, 2006 and 2005, the one-month period ended December 31, 2004, the eleven-month period ended November 30, 2004, and the period from inception (April 2, 2003) to December 31, 2003. The consolidated financial statements and notes have been adjusted to reflect the results of operations, financial position and cash flows of the Partnership combined with TexStar Field Services, L.P., and TexStar GP, LLC (together TexStar) for all periods subsequent to December 1, 2004.

The Partnership s and our predecessors , Regency LLC Predecessor and Regency Gas Services LP, historical results of operations are presented below. See Item 7 Management s Discussions and Analysis of Financial Condition and Results of Operations Items Affecting Comparability of Our Financial Results for a discussion of why our results may not be comparable, either from period to period or going forward.

We refer to Regency Gas Services LLC as Regency LLC Predecessor for periods prior to its acquisition by the HM Capital Investors.

The following table includes the non-GAAP financial measures of EBITDA and total segment margin. We define EBITDA as net income plus interest expense, provision for income taxes and depreciation and amortization expense. We define total segment margin as total revenue, including service fees, less cost of gas and liquids. For a reconciliation of EBITDA and total segment margin to their most directly comparable financial measures calculated and presented in accordance with GAAP (accounting principles generally accepted in the United States), please read Non-GAAP Financial Measures.

	Regency Energy Partners LP			Regency LLC Predecessor	
	Year Ended December 31, 2006	Year Ended December 31, 2005	Period from Acquisition (December 1, 2004) to December 31, 2004	Period from January 1, 2004 to November 30, 2004	Period from Inception (April 2, 2003) to December 31, 2003
	(In thousands except per unit data)				
Statement of Operations Data:					
Total revenue	$ 896,865	$ 709,401	$ 47,857	$ 432,321	$ 186,533
Total operating expense	857,005	695,366	45,112	404,251	178,172
Operating income	39,860	14,035	2,745	28,070	8,361
Other income and deductions					
Interest expense, net	(37,182)	(17,880)	(1,335)	(5,097)	(2,392)

Loss on debt refinancing	(10,761)	(8,480)		(3,022)	
Equity income	532	312	56		
Other income and deductions, net	307	421	8	186	205
Total other income and deductions	(47,104)	(25,627)	(1,271)	(7,933)	(2,187)
Net income (loss) from continuing operations	(7,244)	(11,592)	1,474	20,137	6,174
Discontinued operations		732		(121)	
Net income (loss)	$ (7,244)	$ (10,860)	$ 1,474	$ 20,016	$ 6,174
Less:					
Net income through January 31, 2006	1,564				
Net income (loss) for partners	$ (8,808)				
General partner interest	$ (176)				

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	Regency Energy Partners LP			Regency LLC Predecessor	
	Year Ended December 31, 2006	Year Ended December 31, 2005	Period from Acquisition (December 1, 2004) to December 31, 2004	Period from January 1, 2004 to November 30, 2004	Period from Inception (April 2, 2003) to December 31, 2003
	(In thousands except per unit data)				
Limited partner interest	$ (8,632)				
Basic and diluted net loss per common and subordinated unit	$ (0.21)				
Cash distributions declared per common and subordinated unit	0.94				
Basic and diluted net loss per Class B common unit	(0.12)				
Cash distributions declared per Class B common unit					
Basic and diluted net loss per Class C common unit					
Cash distributions declared per Class C common unit					
Balance Sheet Data (at period end):					
Property, plant and equipment, net	$ 734,034	$ 609,157	$ 328,784		$ 118,986
Total assets	1,013,085	806,740	492,170		164,330
Long-term debt (long-term portion only)	664,700	428,250	248,000		55,387
Net equity	212,657	230,962	181,936		59,856
Cash Flow Data:					
Net cash flows provided by (used in):					
Operating activities	$ 44,156	$ 37,340	$ (4,311)	$ 32,401	$ 6,494
Investing activities	(223,650)	(279,963)	(130,478)	(84,721)	(123,165)
Financing activities	184,947	242,949	132,515	56,380	118,245
Other Financial Data:					
Total segment margin	$ 158,049	$ 77,059	$ 6,870	$ 69,559	$ 23,072
EBITDA	69,592	30,191	4,470	35,242	12,890
Maintenance capital expenditures	16,433	9,158	358	5,548	1,633
Segment Financial and Operating Data:					
Gathering and Processing Segment:					
Financial data:					
Segment margin	$ 113,002	$ 61,387	$ 6,262	$ 61,347	$ 18,805
Operation and maintenance	35,008	22,362	1,655	16,230	6,131

Operating data:					
Natural gas through-put (MMbtu/d)	529,467	345,398	314,812	303,345	211,474
NGL gross production (Bbls/d)	18,587	14,883	16,321	14,487	9,434
Transportation Segment:					
Financial data:					
Segment margin	$ 45,047	$ 15,672	$ 608	$ 8,212	$ 4,267
Operation and maintenance	4,488	1,929	164	1,556	881
Operating data:					
Through-put (MMbtu/d)	587,098	258,194	161,584	192,236	211,569

Non-GAAP Financial Measures

We include the following non-GAAP financial measures: EBITDA and total segment margin. We provide reconciliations of these non-GAAP financial measures to their most directly comparable financial measures as calculated and presented in accordance with GAAP.

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

- financial performance of our assets without regard to financing methods, capital structure or historical cost basis;

- the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make cash distributions to our unitholders and General Partner;

- our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing methods or capital structure; and

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

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.

EBITDA does not include interest expense, income taxes or depreciation and amortization expense. Because we have borrowed money to finance our operations, interest expense is a necessary element of our costs and our ability to generate cash available for distribution. Because we use capital assets, depreciation and amortization are also necessary elements of our costs. Therefore, any measures that exclude these elements have material limitations. To compensate for these limitations, we believe that it is important to consider both net earnings determined under GAAP, as well as EBITDA, to evaluate our performance.

We define total segment margin as total revenues, including service fees, less cost of gas and liquids. Total segment margin is included as a supplemental disclosure because it is a primary performance measure used by our management as it represents the results of product sales, service fee revenues and product purchases, a key component of our operations. We believe total segment margin is an important measure because it is directly related to our volumes and commodity price changes. Operation and maintenance is a separate measure used by management to evaluate operating performance of field operations. Direct labor, insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of our operation and maintenance. These expenses are largely independent of the volumes we transport or process and fluctuate depending on the activities performed during a specific period. We do not deduct operation and maintenance from total revenues in calculating total segment margin because we separately evaluate commodity volume and price changes in total segment margin. As an indicator of our operating performance, total segment margin should not be considered an alternative to, or more meaningful than, net income as determined in accordance with GAAP. Our total segment margin may not be comparable to a similarly titled measure of another company because other entities may not calculate total segment margin in the same manner.

	Regency Energy Partners LP			Regency LLC Predecessor	
	Year Ended December 31, 2006	Year Ended December 31, 2005	Period from Acquisition Date (December 1, 2004) to December 31, 2004	Period from January 1, 2004 to November 30, 2004	Period from Inception (April 2, 2003) to December 31, 2003
			(In thousands)		
Reconciliation of EBITDA to net cash flows provided by (used in) operating activities and to net (loss) income					
Net cash flows provided by (used in) operating activities	$ 44,156	$ 37,340	$ (4,311)	$ 32,401	$ 6,494
Add (deduct):					
Depreciation and amortization	(39,287)	(24,286)	(1,793)	(10,461)	(4,658)
Equity income	532	312	56		
Loss on debt refinancing	(10,761)	(8,480)		(3,022)	
Risk management portfolio value changes	2,262	(11,191)	322		
Unit based compensation expenses	(2,906)				
Gain on the sale of Regency Gas Treating LP assets		626			
Gain on the sale of NGL line pack		628			
Accounts receivable	5,506	43,012	(2,568)	19,832	31,966
Other current assets	(104)	2,644	2,456	1,169	1,070
Accounts payable and accrued liabilities	1,359	(52,651)	(548)	(18,122)	(26,880)
Accrued taxes payable	(492)	(806)	921	(1,475)	(906)
Other current liabilities	(3,148)	(1,269)	242	(502)	(917)
Proceeds from early termination of interest rate swap	(4,940)				
Amount of swap termination proceeds reclassified into earnings	3,862				
Other assets	(3,014)	3,261	6,697	196	5
Other liabilities	(269)				
Net (loss) income	$ (7,244)	$ (10,860)	$ 1,474	$ 20,016	$ 6,174
Add:					
Interest expense, net	37,182	17,880	1,335	5,097	2,392
Depreciation and amortization	39,654	23,171	1,661	10,129	4,324
EBITDA	$ 69,592	$ 30,191	$ 4,470	$ 35,242	$ 12,890
Reconciliation of total segment margin to net (loss) income					
Net (loss) income	$ (7,244)	$ (10,860)	$ 1,474	$ 20,016	$ 6,174

Add (deduct):					
Operation and maintenance	39,496	24,291	1,819	17,786	7,012
General and administrative	22,826	15,039	645	6,571	2,651
Related party expenses	1,630	523			
Management services termination fee	12,542				
Transaction expenses	2,041			7,003	724
Depreciation and amortization	39,654	23,171	1,661	10,129	4,324
Interest expense, net	37,182	17,880	1,335	5,097	2,392
Equity income	(532)	(312)	(56)		
Loss on debt refinancing	10,761	8,480		3,022	
Other income and deductions, net	(307)	(421)	(8)	(186)	(205)
Discontinued operations		(732)		121	
Total segment margin	$ 158,049	$ 77,059	$ 6,870	$ 69,559	$ 23,072

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

The following discussion analyzes our financial condition and results of operations. You should read the following discussion of our financial condition and results of operations in conjunction with our historical consolidated financial statements and notes included elsewhere in this document.

OVERVIEW

We are a Delaware limited partnership formed to capitalize on opportunities in the midstream sector of the natural gas industry. We own and operate significant natural gas gathering and processing assets in north Louisiana, east Texas, south Texas, west Texas and the mid-continent region of the United States, which includes Kansas, Oklahoma, Colorado, and the Texas Panhandle. We are engaged in gathering, processing, marketing and transporting natural gas and natural gas liquids, or NGLs. We connect natural gas wells of producers to our gathering systems through which we transport the natural gas to processing plants operated by us or by third parties. The processing plants separate NGLs from the natural gas. We then sell and deliver the natural gas and NGLs to a variety of markets.

In February 2006, we consummated the initial public offering of our common units. See Formation, Acquisition and Financial Statement Presentation for additional information on our initial public offering.

In August 2006, we acquired all the outstanding equity of TexStar Field Services, L.P. and its general partner, TexStar GP, LLC (the TexStar acquisition), from HMTF Gas Partners II, L.P. (HMTF Gas Partners), an affiliate of HM Capital Partners. Hicks Muse Equity Fund V, L.P. (Fund V) and its affiliates, through HM Capital Partners, control our general partner. Fund V also indirectly owns a majority of, and, through HM Capital Partners, controls HMTF Gas Partners. Because our acquisition of TexStar was a transaction between commonly controlled entities, we have accounted for the transaction in a manner similar to a pooling of interests, and we have updated our historical financial statements to include the financial condition and results of operations of TexStar for periods in which common control exists (December 1, 2004 forward).

HOW WE EVALUATE OUR OPERATIONS

Our management uses a variety of financial and operational measurements to analyze our performance. We view these measures as important factors affecting our profitability and review these measurements on a monthly basis for consistency and trend analysis. These measures include volumes, segment margin and operating and maintenance expenses on a segment basis and EBITDA on a company-wide basis.

Volumes. We must continually obtain new supplies of natural gas to maintain or increase through-put volumes on our gathering and processing systems. Our ability to maintain existing supplies of natural gas and obtain new supplies is affected by (1) the level of workovers or recompletions of existing connected wells and successful drilling activity in areas currently dedicated to our pipelines, (2) our ability to compete for volumes from successful new wells in other areas and (3) our ability to obtain natural gas that has been released from other commitments. We routinely monitor producer activity in the areas served by our gathering and processing systems to pursue new supply opportunities.

To increase through-put volumes on our intrastate pipeline we must contract with shippers, including producers and marketers, for supplies of natural gas. We routinely monitor producer and marketing activities in the areas served by our transportation system in search of new supply opportunities.

Segment Margin. We calculate our Gathering and Processing segment margin as our revenue generated from our gathering and processing operations minus the cost of natural gas and NGLs purchased and other cost of sales, which also includes third-party transportation and processing fees. Revenue includes revenue from the sale of natural gas and NGLs resulting from these activities and fixed fees associated with the gathering and processing natural gas. Our contract portfolio affects our segment margin. See Our Operations for a discussion of our contract portfolio.

We calculate our Transportation segment margin as revenue generated by fee income as well as, in those instances in which we purchase and sell gas for our account, gas sales revenue minus the cost of natural gas that we purchase and transport. Revenue primarily includes fees for the transportation of pipeline-quality natural gas and sales of natural gas transported for our account. Most of our segment margin is fee-based with little or no commodity price risk. We generally purchase pipeline-quality natural gas at a pipeline inlet price adjusted to reflect our transportation fee and we sell that gas at the pipeline outlet. We regard the difference between the purchase price and the sale price as the economic equivalent of our transportation fee.

Total Segment Margin. Segment margin from Gathering and Processing, together with segment margin from Transportation comprise total segment margin. We use total segment margin as a measure of performance. See Item 6 Selected Financial Data Non-GAAP Financial Measures for a reconciliation of this non-GAAP financial measure, total segment margin, to its most directly comparable GAAP measure, net income or loss.

Operation and Maintenance. Operation and maintenance is a separate measure that we use to evaluate operating performance of field operations. Direct labor, insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of our operating and maintenance expenses. These expenses are largely independent of the volumes through our systems but fluctuate depending on the activities performed during a specific period. We do not deduct operation and maintenance from total revenues in calculating segment margin because we separately evaluate commodity volume and price changes in segment margin.

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

- financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make cash distributions to our unitholders and general partners;
- 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 should not be considered as an alternative to net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP. EBITDA is the starting point in determining cash available for distribution, which is an important non-GAAP financial measure for a publicly traded master limited partnership. See Item 6 Selected Financial Data for a reconciliation of EBITDA to net cash flows provided by (used in) operating activities and to net income (loss).

OUR OPERATIONS

We manage our business and analyze and report our results of operations through two business segments:

- Gathering and Processing, in which we provide wellhead to market services to producers of natural gas, including the transport of raw natural gas from the wellhead through gathering systems, processing raw natural gas to separate the NGLs and selling or delivering the pipeline-quality natural gas and NGLs to various markets and pipeline systems; and

Transportation, in which we deliver natural gas from north Louisiana to northeast Louisiana through our 320-mile Regency Intrastate Pipeline system, which has been significantly expanded and extended through our Regency Intrastate Enhancement Project. Our Transportation segment includes certain marketing activities related to our transportation pipelines that are conducted by a separate subsidiary.

Gathering and processing segment

Results of operations from our Gathering and Processing segment are determined primarily by the volumes of natural gas that we gather and process, our current contract portfolio, and natural gas and NGL prices. We measure the performance of this segment primarily by the segment margin it generates. We gather and process natural gas pursuant to a variety of arrangements generally categorized as fee-based arrangements, percent-of-proceeds arrangements and keep-whole arrangements. Under fee-based arrangements, we earn fixed cash fees for the services that we render. Under the latter two types of arrangements, we generally purchase raw natural gas and sell processed natural gas and NGLs. We regard the segment margin generated by our sales of natural gas and NGLs under percent-of-proceeds and keep-whole arrangements as comparable to the revenues generated by fixed fee arrangements.

Percent-of-proceeds and keep-whole arrangements involve commodity price risk to us because our segment margin is based in part on natural gas and NGL prices. We seek to minimize our exposure to fluctuations in commodity prices in several ways, including managing our contract portfolio. In managing our contract portfolio, we classify our gathering and processing contracts according to the nature of commodity risk implicit in the settlement structure of those contracts.

Fee-Based Arrangements. Under these arrangements, we generally are paid a fixed cash fee for performing the gathering and processing service. This fee is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices. A sustained decline in commodity prices, however, could result in a decline in volumes and, thus, a decrease in our fee revenues. These arrangements provide stable cash flows, but minimal, if any, upside in higher commodity price environments.

Percent-of-Proceeds Arrangements. Under these arrangements, we generally gather raw natural gas from producers at the wellhead, transport it through our gathering system, process it and sell the processed gas and NGLs at prices based on published index prices. In this type of arrangement, we retain the sales proceeds less amounts remitted to producers and the retained sales proceeds constitute our margin. These arrangements provide upside in high commodity price environments, but result in lower margins in low commodity price environments. Under these arrangements, our margins typically cannot be negative. We regard the margin from this type of arrangement as an important analytical measure of these arrangements. The price paid to producers is based on an agreed percentage of one of the following: (1) the actual sale proceeds; (2) the proceeds based on an index price; or (3) the proceeds from the sale of processed gas or NGLs or both. Under this type of arrangement, our margin correlates directly with the prices of natural gas and NGLs (although there is often a fee-based component to these contracts in addition to the commodity sensitive component).

Keep-Whole Arrangements. Under these arrangements, we process raw natural gas to extract NGLs and pay to the producer the full thermal equivalent volume of raw natural gas received from the producer in processed gas or its cash equivalent. We are generally entitled to retain the processed NGLs and to sell them for our account. Accordingly, our margin is a function of the difference between the value of the NGLs produced and the cost of the processed gas used to replace the thermal equivalent value of those NGLs. The profitability of these arrangements is subject not only to the commodity price risk of natural gas and NGLs, but also to the price of natural gas relative to NGL prices. These arrangements can provide large profit margins in favorable commodity price environments, but also can be subject to losses if the cost of natural gas exceeds the value of its thermal equivalent of NGLs. Many of our keep-whole contracts include provisions that reduce our commodity price exposure, including (1) provisions that require the keep-whole contract to convert to a fee-based arrangement if the NGLs have a lower value than their thermal equivalent in natural gas,

(2) embedded discounts to the applicable natural gas index price under which we may reimburse the producer an amount in cash for the thermal equivalent volume of raw natural gas acquired from the producer, (3) fixed cash fees for

ancillary services, such as gathering, treating, and compression, or (4) the ability to bypass in unfavorable price environments.

An important aspect of our contract portfolio management strategy is to decrease our keep-whole contract risk exposure. Immediately following the acquisition of our mid-continent assets in 2003, we terminated our month-to-month keep-whole arrangements and replaced them with fee-based or percentage-of-proceeds agreements or variations thereof. In addition, we seek to replace our longer term keep-whole arrangements as they expire or whenever the opportunity presents itself. For the year ended December 31, 2006, 12 percent of our gathering and processing volumes were subject to keep-whole arrangements.

In our Gathering and Processing segment, we are a seller of NGLs and are exposed to commodity price risk. NGLs, condensate and natural gas prices have experienced volatility in recent years in response to changes in supply and demand and market uncertainty. In response to this volatility, we have, since the acquisition of Regency Gas Services LLC by the HM Capital Investors, executed swap contracts settled against ethane, propane, butane and natural gasoline, crude oil and natural gas market prices, supplemented with crude oil put options (historically, changes in the prices of heavy NGLs, such as natural gasoline, have generally correlated with changes in the price of crude oil). The Partnership has executed swap contracts settled against ethane, propane, butane, natural gasoline, crude oil and natural gas market prices. As of March 29, 2007, we have hedged approximately 71 percent of our expected exposure to NGL in 2007 and 2008 and approximately 28 percent in 2009. We have hedged approximately 66 percent of our expected exposure to condensate prices in 2007 and approximately 64 percent in 2008 and 2009. We have hedged approximately 60 percent of our expected exposure to natural gas prices in 2007. We continually monitor our hedging and contract portfolio and expect to continue to adjust our hedge position as conditions warrant.

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 under pricing terms related to a market index. To the extent possible, we match the pricing and timing of our supply portfolio to our sales portfolio in order to lock in our margin and reduce our overall commodity price exposure. To the extent our natural gas position is not balanced, we will be exposed to the commodity price risk associated with the price of natural gas.

Transportation segment

Results of operations from our Transportation segment are determined primarily by the volumes of natural gas transported on our Regency Intrastate Pipeline system and the level of fees charged to our customers or the margins received from purchases and sales of natural gas. We generate revenues and segment margins for our Transportation segment principally under fee-based transportation contracts or through the purchase of natural gas at one of the inlets to the pipeline and the sale of natural gas at an outlet. In the latter case, we generally purchase pipeline-quality natural gas at a pipeline inlet price adjusted to reflect our transportation fee and we sell that natural gas at a pipeline outlet. The differential in the purchase price and the sale price contributes to our segment margin. The margin we earn from our transportation activities is directly related to the volume of natural gas that flows through our system and is not directly dependent on commodity prices. If a sustained decline in commodity prices should result in a decline in volumes, our revenues from these arrangements would be reduced.

Generally, we provide to shippers two types of fee-based transportation services under our transportation contracts:

Firm Transportation. When we agree to provide firm transportation service, we become obligated to transport natural gas nominated by the shipper up to the maximum daily quantity specified in the contract. In exchange for that obligation on our part, the shipper pays a specified reservation charge, whether or not it utilizes the capacity. In most cases, the shipper also pays a commodity charge with respect to quantities actually transported by us.

Interruptible Transportation. When we agree to provide interruptible transportation service, we become obligated to transport natural gas nominated by the shipper only to the extent that we have

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available capacity. For this service the shipper pays no reservation charge but pays a commodity charge for quantities actually shipped.

We provide transportation services under the terms of our contracts and under an operating statement that we have filed and maintain with the FERC with respect to transportation authorized under section 311 of the NGPA.

In addition, we perform a limited merchant function on our Regency Intrastate Pipeline system. This merchant function is conducted by a separate subsidiary. We purchase natural gas from a producer or gas marketer at a receipt point on our system at a price adjusted to reflect our transportation fee and transport that gas to a delivery point on our system at which we sell the natural gas at market price. We regard the segment margin with respect to those purchases and sales as the economic equivalent of a fee for our transportation service. These contracts are frequently settled in terms of an index price for both purchases and sales. In order to minimize commodity price risk, we attempt to match sales with purchases at the index price on the date of settlement.

Our Regency Intrastate Pipeline enables us to provide transportation services from the three largest natural gas producing fields in Louisiana. Prior to the completion of the final phase of the project in December 2005, we were transporting approximately 265,000 MMBtu/d under existing contracts. On March 1, 2007, we had definitive agreements for 562,900 MMBtu/d of firm transportation on the Regency Intrastate Pipeline system, of which 500,679 MMBtu/d was utilized in February 2007. During the month of February 2007, we also provided 195,395 MMBtu/d of interruptible transportation. Additionally, we are currently engaged in discussions with other parties interested in utilizing the system s remaining firm transportation capacity.

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 incorrect, our actual results may vary materially from our expected results.

Natural Gas Supply, Demand and Outlook. Natural gas remains a critical component of energy consumption in the United States. The industrial and electricity generation sectors currently account for the largest usage of natural gas in the United States.

We believe that current natural gas prices and the existing strong demand for natural gas will continue to result in relatively high levels of natural gas-related drilling in the United States as producers seek to increase their level of natural gas production. Although the natural gas reserves in the United States have increased overall in recent years, a corresponding increase in production has not been realized. We believe that this lack of increased production is attributable to insufficient pipeline infrastructure, the continued depletion of existing wells and a tight labor and equipment market. We believe that an increase in United States natural gas production and additional sources of supply such as liquidified natural gas and other imports of natural gas will be required for the natural gas industry to meet the expected increased demand for natural gas in the United States.

All of the areas in which we operate are experiencing significant drilling activity. Although we anticipate continued high levels of exploration and production activities in all of these areas, fluctuations in energy prices can affect production rates over time and levels of investment by third parties in exploration for and development of new natural gas reserves. We have no control over the level of natural gas exploration and development activity in the areas of our operations.

Gathering and Processing Segment Margins. In keeping with our strategy of reducing commodity price exposure, we have adjusted our contract portfolio through renegotiation of certain keep-whole contracts, resulting in a shift of our overall natural gas position to a long position going forward, while retaining a long physical NGL position. We believe that this adjusted portfolio effectively hedges our overall exposure to volatility in fractionation spreads. Our profitability is now positively impacted if natural gas or NGLs prices

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increase and negatively impacted if natural gas or NGLs prices decrease. The prices of natural gas and NGLs are volatile and beyond our control.

Effect of Interest Rates and Inflation. Interest rates on existing and future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. Although increased financing costs could limit our ability to raise funds in the capital markets, we expect in this regard to remain competitive with respect to acquisitions and capital projects since our competitors would face similar circumstances.

Inflation in the United States has been relatively low in recent years and did not have a material effect on our results of operations in 2004, 2005 or 2006. It may in the future, however, increase the cost to acquire or replace property, plant and equipment and may increase the costs of labor and supplies. Our operating revenues and costs are influenced to a greater extent by price changes in natural gas and NGLs. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass along increased costs to our customers in the form of higher fees.

FORMATION, ACQUISITION AND FINANCIAL STATEMENT PRESENTATION

Our Formation and Initial Public Offering

We are a Delaware limited partnership formed in September 2005 to own and operate Regency Gas Services LP. Prior to the completion of our initial public offering, Regency Gas Services LLC was owned by the HM Capital Investors.

Formation of Regency Gas Services LLC Regency Gas Services LLC was organized on April 2, 2003 by a private equity fund for the purpose of acquiring, managing and operating natural gas gathering, processing and transportation assets. Regency Gas Services LLC had no operating history prior to the acquisition of the assets from affiliates of El Paso Energy Corporation and Duke Energy Field Services, L.P. discussed below.

Acquisition of El Paso Assets In June 2003, Regency LLC Predecessor acquired certain natural gas gathering, processing and transportation assets from subsidiaries of El Paso Corporation for $119,541,000. The assets acquired consisted of gathering, processing and transportation assets located in north Louisiana and gathering and processing assets located in the mid-continent region of the United States.

Prior to our acquisition of these assets, these assets were operated as components of El Paso s much larger midstream operations. Immediately following our acquisition of these assets, we changed the manner in which these assets were operated. In that regard, we initiated, and continue to implement, a strategy to reshape the revenue structure of the acquired assets to expand revenues, increase margins and decrease exposure to market volatility.

Acquisition of Duke Energy Field Services Assets In March 2004, Regency LLC Predecessor acquired certain natural gas gathering and processing assets from Duke Energy Field Services, LP for $67,264,000, including transactional costs. The assets acquired consisted of gathering and processing assets located in west Texas and represent substantially all of our existing west Texas assets.

Prior to our acquisition of these assets, these assets were operated as components of Duke Energy Field Services much larger midstream operations. As with the assets acquired from El Paso, immediately following our acquisition of these assets, we implemented significant operational changes designed to expand revenues, increase margins and limit exposure to market volatility. We promptly changed the manner in which pipeline-quality natural gas was marketed from these assets.

Others In April 2004, we completed the purchase of gas processing interests located in Louisiana and Texas from Cardinal Gas Services LLC (Cardinal) for $3,533,000 in cash. In May 2005, we sold all of the assets acquired from Cardinal, together with certain related assets, for $6,000,000. After the allocation of $977,000 of goodwill, the resulting gain was $626,000. We have treated these operations as a discontinued operation.

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The HM Capital Investors Acquisition of Regency Gas Services LLC On December 1, 2004, the HM Capital Investors acquired all of the outstanding equity interests in our predecessor, Regency Gas Services LLC, from its previous owners. The HM Capital Investors accounted for this acquisition as a purchase, and purchase accounting adjustments, including goodwill and other intangible assets, have been pushed down and are reflected in the financial statements of Regency Gas Services LLC for the period subsequent to December 1, 2004. We refer to this transaction as the HM Capital Transaction. For periods prior to the HM Capital Transaction, we designated such periods as Regency LLC Predecessor.

Initial Public Offering Prior to the closing of our initial public offering on February 3, 2006, Regency Gas Services LLC was converted into a limited partnership named Regency Gas Services LP, and was contributed to us by Regency Acquisition LP, a limited partnership indirectly owned by the HM Capital Investors, in exchange for 5,353,896 common units, 19,103,896 subordinated units, the incentive distribution rights, a continuation of its 2 percent general partner interest in us, and a right to receive $195,757,000 of cash proceeds from our initial public offering. The cash proceeds constituted a reimbursement of a corresponding amount of capital expenditures comprising most of the initial investment by the HM Capital Investors in Regency Gas Services LLC. In addition, approximately $48,000,000 in cash and accounts receivable were distributed by Regency Gas Services LLC to Regency Acquisition LP and then to the HM Capital Investors immediately prior to the contribution of Regency Gas Services LLC to us. These current assets were replenished with proceeds from the offering.

On March 8, 2006 we closed the sale of an additional 1,400,000 common units at a price of $20 per unit as the underwriters exercised, in part, their option to purchase additional units. The net proceeds from the sale were used by us to redeem an equivalent number of common units held by Regency Acquisition LP for the benefit of the HM Capital Investors.

We paid $9,000,000 of the proceeds from our initial public offering to terminate our ten-year financial advisory, monitoring and oversight agreements with HM Capital Partners. In the first quarter of 2006 we expensed these costs.

Acquisition of TexStar Field Services, L.P.

On August 15, 2006, we acquired all the outstanding equity of TexStar for $348,909,000, which consisted of $62,074,000 in cash, the issuance of 5,173,189 Class B common units valued at $119,183,000 to an affiliate of HM Capital, and the assumption of $167,652,000 of TexStar s outstanding bank debt. Because the TexStar acquisition was a transaction between commonly controlled entities, we accounted for the TexStar acquisition in a manner similar to a pooling of interests. As a result, our historical financial statements and the historical financial statements of TexStar have been combined to reflect the historical operations, financial position and cash flows for periods in which common control existed, December 1, 2004 forward.

Enbridge Asset Acquisition

TexStar acquired two sulfur recovery plants, one NGL plant and 758 miles of pipelines in east and south Texas (the Enbridge assets) from subsidiaries of Enbridge for $108,282,000 inclusive of transaction expenses on December 7, 2005 (the Enbridge acquisition). The Enbridge acquisition was accounted for using the purchase method of accounting. The results of operations of the Enbridge assets are included in our statements of operations beginning December 1, 2005. The purchase price was allocated to gas plants and buildings ($42,361,000), gathering and transmission systems ($65,002,000) and other property, plant and equipment ($919,000) as of December 1, 2005. TexStar assumed no material liabilities in this acquisition.

ITEMS AFFECTING 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:

Regency LLC Predecessor commenced active operations in June 2003 with the acquisition of the El Paso assets. As a result, we do not have any material financial results for periods prior to June 2003 and our results of operations for the period ended December 31, 2003 includes only seven months of financial results.

Regency LLC Predecessor acquired the Duke Energy Field Services assets in March 2004. As a result, our financial results for periods prior to March 2004 do not include the financial results of the Duke Energy Field Services assets.

In connection with the acquisition of Regency Gas Services LLC by the HM Capital Investors on December 1, 2004, the purchase price was pushed-down to the financial statements of Regency Gas Services LLC. As a result of this push-down accounting, the book basis of our assets was increased to reflect the purchase price, which had the effect of increasing our depreciation and amortization expense. Also, the increased level of debt incurred in connection with the acquisition increased our interest expense subsequent to December 1, 2004.

In December 2004 we undertook a hedging program. Effective July 1, 2005 we designated certain commodity and interest rate swap instruments for hedge accounting treatment in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. For the periods from December 1, 2004 through June 30, 2005 unrealized and realized gains and losses on the commodity swaps were recorded in unrealized/realized gain (loss) from risk management activities in our statements of operations. For the six months ended June 30, 2005 unrealized gains and losses on the interest rate swap were recorded in interest expense, net. Effective July 1, 2005, to the extent the hedges were effective, any unrealized gains or losses on these instruments were recorded in other comprehensive income (loss) during the lives of the instruments, which we believe results in financial results that are not comparable for the affected periods.

TexStar acquired the Enbridge assets on December 7, 2005. As a result, our historical results for the periods prior to December 1, 2005 do not include the financial results from the operation of these assets.

We completed our Regency Intrastate Enhancement Project and the pipeline, as expanded and extended, began operations on December 28, 2005. In 2006, we have increased the capacity total through-put capacity to 910 MMcf/d by adding looping to parts of the Regency Intrastate Pipeline system.

The TexStar acquisition is a transaction between commonly controlled entities, and we accounted for this acquisition in a manner similar to a pooling of interests. As a result, the historical financial statements of the Partnership and TexStar have been combined to reflect the historical operations, financial position and cash flows during the periods in which common control existed from December 1, 2004 forward. Most of the TexStar significant operating activity commenced in December 2005. As a result, the TexStar historical operations, financial position and cash flows are not comparable to prior periods.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in the financial statements and notes. Although these estimates are based on management s best available knowledge of current and expected future events, actual results could be different from those estimates. We believe that the following are the more critical judgment areas in the application of our accounting policies that currently affect our financial condition and results of operations.

Revenue and Cost of Sales Recognition. We record revenue and cost of gas and liquids on the gross basis for those transactions where we act as the principal and take title to gas that we purchase for resale. When our customers pay us a fee for providing a service such as gathering or transportation we record the fees separately in revenues. In March 2006, we implemented a process for estimating certain revenue and expenses as actual amounts are not confirmed until after the financial closing process due to the standard settlement dates in the gas industry. We calculate estimated revenues using actual pricing and nominated volumes. In the subsequent production month, we reverse the accrual and record the actual results. Prior to the settlement date, we record actual operating data to the extent available, such as actual operating and maintenance and other expenses. We do not expect actual results to differ materially from our estimates.

Risk Management Activities. In order to protect ourselves from commodity and interest rate risk, we pursue hedging activities to minimize those risks. These hedging activities rely upon forecasts of our expected operations and financial structure over the next three years. If our operations or financial structure are significantly different from these forecasts, we could be subject to adverse financial results as a result of these hedging activities. We mitigate this potential exposure by retaining an operational cushion between our forecasted transactions and the level of hedging activity executed. We monitor and review hedging positions regularly.

From the inception of our hedging program in December 2004 through June 30, 2005, we used mark-to-market accounting for our commodity and interest rate swaps. We recorded realized gains and losses on hedge instruments monthly based upon the cash settlements and the expiration of option premiums. The settlement amounts varied due to the volatility in the commodity market prices throughout each month.

Effective July 1, 2005, we elected hedge accounting under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities , as amended, and determined the then outstanding hedges, excluding crude oil put options, qualified for hedge accounting. Accordingly, we record the unrealized changes in fair value in other comprehensive income (loss) to the extent the hedge are effective. Prior to July 1, 2005, we had recorded unrealized losses and gains in the fair market value of commodity-related derivative contracts and unrealized gains on an interest rate swap into revenues and interest expense, net, respectively.

Purchase Method of Accounting. We make various assumptions in determining the fair values of acquired assets and liabilities. In order to allocate the purchase price to the business units, we develop fair value models with the assistance of outside consultants. These fair value models apply discounted cash flow approaches to expected future operating results, considering expected growth rates, development opportunities, and future pricing assumptions. An economic value is determined for each business unit. We then determine the fair value of the fixed assets based on estimates of replacement costs. Intangible assets acquired consist primarily of licenses, permits and customer contracts. We make assumptions regarding the period of time it would take to replace these licenses and permits. We assign value using a lost profits model over that period of time necessary to replace the licenses and permits. We value the customer contracts using a discounted cash flow model. We determine liabilities assumed based on their expected future cash outflows. We record goodwill as the excess of the cost of each business unit over the sum of amounts assigned to the tangible assets and separately recognized intangible assets acquired less liabilities assumed of the business unit.

Depreciation Expense and Cost Capitalization. Our assets consist primarily of natural gas gathering pipelines, processing plants, and transmission pipelines. We capitalize all construction-related direct labor and material costs, as well as indirect construction costs. Indirect construction costs include general engineering and the costs of funds used in construction. Capitalized interest represents the cost of funds used to finance the construction of new facilities and is expensed over the life of the constructed asset through the recording of depreciation expense. We capitalize the costs of renewals and betterments that extend the useful life, while we expense the costs of repairs, replacements and maintenance projects as incurred.

We generally compute depreciation using the straight-line method over the estimated useful life of the assets. Certain assets such as land, NGL line pack and natural gas line pack are non-depreciable. The computation of depreciation expense requires judgment regarding the estimated useful lives and salvage value of assets. As circumstances warrant, we review depreciation estimates to determine if any changes are needed. Such changes could involve an increase or decrease in estimated useful lives or salvage values, which would impact future depreciation expense.

Equity Based Compensation. On December 12, 2005, the compensation committee of the board of directors of Regency GP LLC approved a long-term incentive plan (LTIP) for our employees, directors and consultants covering an aggregate of 2,865,584 common units. Awards under the LTIP have been made since the completion of our initial public offering. LTIP awards generally vest over a three year period on the basis of one-third of the award each year. The options have a maximum contractual term, expiring ten years after

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the grant date. Options granted were valued using the Black-Scholes Option Pricing Model, assuming 15 percent volatility in the unit price, a ten year term, a strike price equal to the grant-date price per unit, a distribution per unit of $1.40 per year for the majority of the grants made during the year ended December 31, 2006, a risk-free rate of 4.25 percent, and an average exercise of the options of four years after vesting is complete. We have based the assumption that option exercises, on average, will be four years from the vesting date on the average of the mid-points from vesting to expiration of the options.

We make the same distributions to the holders of unvested restricted common units as those paid to common unit holders. Restricted common units vest over a period of three years. Upon the vesting, we intend to settle these obligations with common units. Accordingly, we expect to recognize an aggregate of $11,469,000 of compensation expense related to the grants under LTIP, or $3,823,000 for each of the three years of the vesting period for such grants as of December 31, 2006. This expected compensation expense assumes forfeitures of five percent for which compensation expense will not be recognized. We will record an adjustment to compensation expense to the extent our actual forfeiture rate is different for the expected rate in the first quarter of the fiscal year. We adopted SFAS 123(R) Share-Based Payment in the first quarter of 2006, which had no impact on our consolidated financial position, results of operations or cash flows as no LTIP awards were outstanding during 2005.

In March 2007, the board of directors of Regency GP LLC approved and granted 191,000 LTIP awards of the Partnerships restricted common units that generally vest on a basis of one-third each year. The grant date fair value of these awards is $5,291,000.

RESULTS OF OPERATIONS

Year Ended December 31, 2006 vs. Year Ended December 31, 2005

The table below contains key company-wide performance indicators related to our discussion of the results of operations.

	Year Ended December 31,			
	2006	2005	Change	Percent
		(In thousands)		
Total revenues	$ 896,865	$ 709,401	$ 187,464	26%
Cost of gas and liquids	738,816	632,342	106,474	17
Total segment margin(1)	158,049	77,059	80,990	105
Operation and maintenance	39,496	24,291	15,205	63
General and administrative	22,826	15,039	7,787	52
Related party expenses	1,630	523	1,107	212
Management services termination fee	12,542		12,542	n/m
Transaction expenses	2,041		2,041	n/m
Depreciation and amortization	39,654	23,171	16,483	71
Operating income	39,860	14,035	25,825	184
Interest expense, net	(37,182)	(17,880)	19,302	108
Equity income	532	312	220	71
Loss on debt refinancing	(10,761)	(8,480)	2,281	27
Other income and deductions, net	307	421	(114)	(27)

Net loss from continuing operations	(7,244)	(11,592)	4,348	38
Discontinued operations		732	(732)	n/m
Net loss	$ (7,244)	$ (10,860)	$ 3,616	33%
System inlet volumes (MMBtu/d)(2)	1,010,642	603,592	407,050	67%

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(1) For a reconciliation of total segment margin to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read Item 6 Selected Financial Data

(2) System inlet volumes include total volumes taken into our gathering and processing and transportation systems. n/m = not meaningful The table below contains key segment performance indicators related to our discussion of our results of operations.

The table below contains key segment performance indicators related to our discussion of our results of operations.

	Year Ended December 31, 2006	2005	Change	Percent
		(In thousands)		
Gathering and Processing Segment				
Financial data:				
Segment margin(1)	$ 113,002	$ 61,387	$ 51,615	84%
Operation and maintenance	35,008	22,362	12,646	57
Operating data:				
Through-put (MMBtu/d)	529,467	345,398	184,069	53
NGL gross production (Bbls/d)	18,587	14,883	3,704	25
Transportation Segment				
Financial data:				
Segment margin(1)	$ 45,047	$ 15,672	$ 29,375	187%
Operation and maintenance	4,488	1,929	2,559	133