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

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	**16-1731691**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
1700 Pacific Avenue, Suite 2900 Dallas, Texas	**75201**
(Address of principal executive offices)	*(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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Indenture
Computation or Ratio of Earnings to Fixed Charges
Code of Business Conduct
List of Subsidiaries
Consent of Deloitte & Touche LLP
Certifications Pursuant to Rule 13a-14(a)
Certifications Pursuant to Rule 13a-14(a)
Certifications Pursuant to Section 1350
Certifications Pursuant to Section 1350
Balance Sheet of Regency GP LP

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 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 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 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;

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 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.

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.

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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 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, 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

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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 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

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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.

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)				

	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.

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	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

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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 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 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

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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

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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 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
Operating data:				
Through-put (MMBtu/d)	587,098	258,194	328,904	127

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

Net loss. Net loss for the year ended December 31, 2006 decreased $3,616,000 compared with the year ended December 31, 2005. The decrease in net loss was primarily attributable to an increase in total segment margin of $80,990,000 primarily due to increased contributions from the Transportation segment resulting from the completion on our Regency Intrastate Enhancement Project in December 2005, a full year of segment margin from our TexStar acquisition and increased performance from the remainder of the Gathering and Processing segment. The increase in total segment margin was offset by increases in the following expenses: (1) interest expense, net increased $19,302,000 primarily due to increased levels of borrowing to fund acquisitions and capital expenditures; (2) depreciation and amortization expense increased $16,483,000 primarily due to a full year of expense in 2006 versus a partial year s expense in 2005 due to the timing of acquisitions and completion of capital projects; (3) operation and maintenance increased $15,205,000 primarily due to a full year of expense in 2006 for the TexStar; (4) management service termination fees of $12,542,000 in 2006, which were not present in 2005; (5) general and administrative expenses increased $7,787,000 primarily resulting from TexStar general and administrative expenses, the accrual of non-cash expense associated with our LTIP and higher employee-related expenses associated with the hiring of key personnel to assist in achieving our strategic objectives; (6) loss on debt refinancing increased $2,281,000 resulting from increased write-offs of capitalized debt issuance costs related to certain credit facilities that we refinanced in 2006; and (7) transaction expenses of $2,041,000 recorded in 2006 related to the TexStar acquisition.

Segment Margin. Total segment margin for the year ended December 31, 2006 increased to $158,049,000 from $77,059,000 for the year ended December 31, 2005, representing a 105 percent increase.

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Gathering and Processing segment margin for the year ended December 31, 2006 increased to $113,002,000 from $61,387,000 for the year ended December 31, 2005, representing an 84 percent increase. The major elements driving this increase in segment margin are as follows:

$4,553,000 contributed by the Como assets that were acquired on July 25, 2006;

$23,513,000 attributable to the operations of the other TexStar assets for a full year in 2006 versus one month of operations in 2005;

$13,986,000 in non-cash losses due to changes to the value of risk management assets for which we applied to mark-to-market accounting in the first six months of 2005 prior to our election of hedge accounting;

$6,347,000 contributed by the Elm Grove and Dubberly refrigeration plants beginning in May 2006 (Elm Grove) and December 2006 (Dubberly); and

$3,216,000 of other changes.

Transportation segment margin for the year ended December 31, 2006 increased to $45,047,000 from $15,672,000 for the year ended December 31, 2005, a 187 percent increase. This increase was attributable to the expansion and extension of the line completed in late 2005, as well as additional improvements in 2006. The major drivers of this growth are as follows:

$15,931,000 attributable to increased volume through-put;

$9,443,000 attributable to increased average fees for service; and

$4,001,000 of marketing activity generated by our merchant function.

Operation and Maintenance. Operation and maintenance expenses for the year ended December 31, 2006 increased to $39,496,000 from $24,291,000 for the year ended December 31, 2005, representing a 63 percent increase. This increase resulted primarily from $13,248,000 higher expenses associated with TexStar. Also contributing to the increase from the transportation segment were higher employee-related expenses of $421,000 primarily for overtime associated with maintenance events and increased non-income taxes of $1,665,000, primarily property taxes related to our Regency Intrastate Enhancement Project.

General and Administrative. General and administrative expenses for the year ended December 31, 2006 increased to $22,826,000 from $15,039,000 for the corresponding period in 2005. The increase was attributable in part to higher employee-related expenses of $3,300,000, including higher salary expense associated with hiring key personnel to assist in achieving our strategic objectives. Also contributing to the increase was the accrual of non-cash expense of $2,906,000 associated with our long-term incentive plan. TexStar contributed $1,519,000 to the increase in general and administrative expense.

Management Services Termination Fee. In the three months ended March 31, 2006 we recorded a one-time charge of $9,000,000 for the termination of two long-term management services contracts in connection with our initial public offering, paid with proceeds from the initial public offering. In the three months ended September 30, 2006 we recorded a one-time charge of $3,542,000 for the termination of a management services contract associated with our TexStar acquisition.

Transaction Expenses. We incurred transaction expenses of $2,041,000 in 2006 related to our TexStar acquisition. Since our TexStar acquisition involved entities under common control, we accounted for the transaction in a manner similar to a pooling of interests and we expensed the transaction costs.

Depreciation and Amortization. Depreciation and amortization expense for the year ended December 31, 2006 increased to $39,654,000 from $23,171,000 for the year ended December 31, 2005, representing a 71 percent increase. Depreciation and amortization expense increased $7,261,000 primarily due to the higher depreciable basis in the transportation segment resulting from the completion of our Regency Intrastate Enhancement Project in December 2005. The new depreciable basis of assets from our TexStar acquisition in the Gathering and Processing segment contributed $6,898,000 to the increase. Depreciation and amortization

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expense in the remainder of the Gathering and Processing segment increased $1,977,000 due primarily to the completion of various capital projects.

Interest Expense, Net. Interest expense, net for the year ended December 31, 2006 increased to $37,182,000 from $17,880,000 for the prior year period. Of the $19,302,000 increase, $19,226,000 was attributable to increased borrowings, $3,166,000 was attributable to increased interest rates, and $771,000 was attributable to reduced unrealized gains on mark-to-market accounting for interest rate swaps, offset by $3,862,000 of proceeds from the early termination of three interest rate swap contracts reclassified into earnings from accumulated other comprehensive income.

Loss on Debt Refinancing. For the year ended December 31, 2006 we expensed $10,761,000 of debt issuance costs to amend and restate our credit facility, of which $5,135,000 was associated with repaying TexStar s credit facility as part of our TexStar acquisition. For the year ended December 31, 2005, as required, we wrote off $8,480,000 of debt issuance costs to amend our credit facility.

Year Ended December 31, 2005 vs. Combined Year Ended December 31, 2004

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

	Regency Energy Partners LP	Regency LLC Predecessor (Combined)		
	Year Ended December 31,			
	2005	2004(3)	Change	Percent
	(In thousands)			
Total revenues	$ 709,401	$ 480,178	$ 229,223	48%
Cost of gas and liquids	632,342	403,749	228,593	57
Total segment margin(1)	77,059	76,429	630	1
Operation and maintenance	24,291	19,605	4,686	24
General and administrative	15,039	7,216	7,823	108
Related party expenses	523		523	n/m
Transaction expenses		7,003	(7,003)	n/m
Depreciation and amortization	23,171	11,790	11,381	97
Operating income	14,035	30,815	(16,780)	(54)
Interest expense, net	(17,880)	(6,432)	11,448	178
Equity income	312	56	256	457
Loss on debt refinancing	(8,480)	(3,022)	5,458	181
Other income and deductions, net	421	194	227	117
Net (loss) income from continuing operations	(11,592)	21,611	(33,203)	(154)
Discontinued operations	732	(121)	853	705

Net (loss) income	$	(10,860)	$	21,490	$	(32,350)	(151)%
System inlet volumes (MMBtu/d)(2)		603,592		494,816		108,776	22%

(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 Non-GAAP Financial Measures.

(2) System inlet volumes include total volumes taken into our gathering and processing and transportation systems.

(3) We combined the results of operations for the period from acquisition (December 1, 2004) of the Predecessor and the period from January 1, 2004 to November 30, 2004 of the Regency LLC Predecessor to provide an annual reporting period for a more meaningful comparison versus the year ended

December 31, 2005. To the extent operations for the 2005 period are not comparable to the combined 2004 period; we have disclosed such differences in the discussion of results of operations. See the separate discussion of the one month ended December 31, 2004.

n/m = not meaningful

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

	Regency Energy Partners LP	Regency LLC Predecessor (Combined)		
	Year Ended December 31,			
	2005	2004(1)	Change	Percent
	(In thousands)			
Gathering and Processing Segment				
Financial data:				
Segment margin(2)	$ 61,387	$ 67,609	$ (6,222)	(9)%
Operation and maintenance	22,362	17,885	4,477	25
Operating data:				
Through-put (MMBtu/d)	345,398	305,176	40,222	13
NGL gross production (Bbls/d)	14,883	15,129	(246)	(2)
Transportation Segment				
Financial data:				
Segment margin(2)	$ 15,672	$ 8,820	$ 6,852	78%
Operation and maintenance	1,929	1,720	209	12
Operating data:				
Through-put (MMBtu/d)	258,194	189,640	68,554	36

(1) We combined the results of operations for the period from acquisition (December 1, 2004) of the Predecessor and the period from January 1, 2004 to November 30, 2004 of the Regency LLC Predecessor to provide an annual reporting period for a more meaningful comparison versus the year ended December 31, 2005. To the extent operations for the 2005 period are not comparable to the combined 2004 period; we have disclosed such differences in the discussion of results of operations. See the separate discussion of the one month ended December 31, 2004.

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

Net Income. Net income for the year ended December 31, 2005 decreased $32,350,000 compared with the combined year ended December 31, 2004. The primary reasons for this decrease are: (1) interest expense, net increased $11,448,000 primarily due to higher net interest expense related to debt incurred to fund the HM Capital Transaction and (on a pooled accounting basis) the TexStar acquisition; (2) depreciation and amortization expense increased $11,381,000 primarily due to our higher depreciable basis following the fair value adjustments recorded to property, plant and equipment in the application of the purchase method of accounting for the HM Capital Transaction; (3) the increase in debt issuance costs of $5,458,000 for the ended December 31, 2005 due to amending our credit facilities; (4) general and administrative expense increased $7,823,000 primarily as a result of higher employee-related expenses and professional and consulting expenses; (5) operation and maintenance expenses increased $4,686,000 primarily due to TexStar, our west Texas facilities operating twelve months in 2005 versus ten months in 2004, and higher taxes, other than income; and (6) a decrease of $7,003,000 in transaction expenses incurred in 2004 not incurred in 2005.

Total Segment Margin. Total segment margin for the year ended December 31, 2005 increased to $77,059,000 from $76,429,000 for the combined year ended December 31, 2004, representing a 1 percent increase. This increase was attributable in part to increased pipeline through-put volumes in the Transportation segment, which produced additional margin of $7,200,000. In December 2005, operations from TexStar in the

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Gathering and Processing segment contributed approximately $5,200,000 in total segment margin. In the remainder of the Gathering and Processing segment, pricing effects were negligible, as $10,757,000 of increased total segment margin attributable to commodity prices was offset by $10,757,000 in hedge settlements, demonstrating the effectiveness of our hedging program. Non-cash losses caused by the net change in the fair value of derivative contracts during such time as the contracts were not designated as hedges in 2005, together with the expiration of certain crude oil put options reduced total segment margin by $11,486,000.

Segment margin for the Gathering and Processing segment for the year ended December 31, 2005 decreased to $61,387,000 from $67,609,000 for the combined year ended December 31, 2004, representing a 9 percent decline. The elements driving this reduction in segment margin are as follows:

- In December 2005, operations from TexStar contributed $5,200,000 in segment margin;
- Other than the TexStar margin, $300,000 of increased segment margin was attributable to increased through-put volumes;
- Other than the TexStar margin, pricing effects in 2005 were negligible, as $10,757,000 of increased segment margin attributable to higher commodity prices was offset by $10,757,000 in cash hedge settlements;
- $11,486,000 of decreased segment margin attributable to non-cash losses reflecting the net change in the fair value of derivatives contracts during the first six months of 2005 and the expiration of certain crude oil put option in 2005, and
- Segment margin in 2004 was increased by $322,000 of non-cash gains reflecting the net change in the fair value of derivative contracts for the period.

Segment margin for the Transportation segment for the year ended December 31, 2005 increased to $15,672,000 from $8,820,000 for the comparable combined period in 2004, a 78 percent increase. The increase was attributable to increased through-put volumes across the system in 2005.

Operation and Maintenance. Operation and maintenance for the year ended December 31, 2005 increased to $24,291,000 from $19,605,000 for the combined year ended December 31, 2004, representing a 24 percent increase. This increase was attributable in part to operation and maintenance of $2,479,000 incurred in December 2005 associated with TexStar in the Gathering and Processing segment. Also contributing to the increase were higher operation and maintenance of $969,000 associated with our west Texas assets in the Gathering and Processing segment for the full year ended December 31, 2005 as compared to ten months in 2004. Higher property taxes in the mid-continent region within the Gathering and Processing segment resulted in an increase of $848,000. Also contributing to the increase in operating and maintenance expenses were higher materials and parts expense of $713,000 in the Transportation segment. These increases were partially offset by lower employee costs and rental expense of $285,000 in the mid-continent region of the Gathering and Processing Segment related to our previously planned shut down of our Lakin gas processing plant.

General and Administrative. General and administrative expense increased to $15,039,000 in the year ended December 31, 2005 from $7,216,000 for the combined year ended December 31, 2004. This increase was primarily attributable to higher employee-related expenses of $3,061,000 for higher salary expense associated with increased headcount and bonus accruals. Also contributing to the increase were increased professional and consulting expenses of $2,931,000, consisting primarily of legal fees for regulatory and contract related matters, business development expenses and consulting fees for Sarbanes-Oxley compliance support. Further contributing to the increase were higher management fees of $694,000, resulting from our relationship with HM Capital Partners.

Transaction Expenses. Regency LLC Predecessor incurred non-recurring expenses related to the HM Capital Transaction in the amount of $7,003,000 in 2004. These expenses consisted of compensation, legal and other expenses and were paid prior to the HM Capital Transaction.

Depreciation and Amortization. Depreciation and amortization increased to $23,171,000 in the year ended December 31, 2005 from $11,790,000 for the combined year ended December 31, 2004, representing a 97 percent increase. Depreciation expense increased $9,602,000 primarily due to the acquisition of Regency Gas Services LLC by the HM Capital Investors in December 2004, which increased the book basis of our depreciable assets to their fair market value. Also contributing to the increase was the amortization of identifiable intangible assets of $1,681,000 in the 2005 period related to definite lived intangible assets that were recorded as part of the HM Capital Transaction.

Interest Expense, Net. Interest expense, net increased $11,448,000, or 178 percent, in the year ended December 31, 2005 compared to the combined year ended December 31, 2004 due to higher net interest expense of $10,611,000, primarily related to debt incurred to fund the HM Capital Transaction and to a lesser extent the TexStar acquisition, and increased amortization of debt issuance costs of $832,000.

Loss on Debt Refinancing. In the years ended December 31, 2005 and 2004, we expensed $8,480,000 and $3,022,000, respectively, of debt refinancing costs as a result of amendments to our credit facilities. The $8,480,000 write-off consisted of (i) $5,800,000 of unamortized debt issuance costs, (ii) $1,924,000 of costs incurred in July 2005 and (iii) $756,000 of costs incurred in November 2005 in connection with amendments to our credit facilities. The write-off for the combined year ended December 31, 2004 consisted of unamortized debt issuance costs.

Federal Income Tax. As a pass-through entity, we are not subject to federal income taxes. The liability for federal income taxes associated with income produced by our business is passed through to and recognized by entities that are investors in our indirect parent.

Discontinued Operations. On April 1, 2004, we completed the purchase of natural gas processing and treating interests located in Louisiana and Texas from Cardinal for $3,533,000. On May 2, 2005, we sold all of the assets acquired from Cardinal, together with certain related assets, for $6,000,000. The results of these operations are presented as discontinued operations, and we recorded a gain on the sale of $626,000 during the year ended December 31, 2005.

The Month of December 2004

The HM Capital Investors purchased Regency Gas Services LLC effective December 1, 2004. As a result of accounting for the acquisition as a purchase and using push-down accounting, we incurred additional depreciation and amortization expense. Depreciation and amortization expense for this one month increased over the preceding monthly amount by $669,000 or 67 percent, resulting primarily from the step-up in basis of tangible assets as well as the recording of new identifiable intangible assets from the purchase price allocation. The additional interest expense resulted primarily from higher levels of borrowings associated with the acquisition. These levels of borrowings increased to $250,000,000 at December 1, 2004 from $66,599,000 at December 31, 2003.

OTHER MATTERS

Legal. The Partnership is involved in various claims and lawsuits incidental to its business. In the opinion of management, these claims and lawsuits in the aggregate will not have a material adverse effect on our business, financial condition, results of operations or cash flows.

Environmental Matters. For information regarding environmental matters, please read Item 1 Business Regulation Environmental Matters.

LIQUIDITY AND CAPITAL RESOURCES

We expect our sources of liquidity to include:

- cash generated from operations;
- borrowings under our credit facility;

- debt offerings; and
- issuance of additional partnership units.

We believe that the cash generated from these sources will be sufficient to meet our minimum quarterly cash distributions and our requirements for short-term working capital and growth capital expenditures for the next twelve months.

Cash Flows and Capital Expenditures

See Item 7 Management s Discussions and Analysis of Financial Condition and Results of Operations Items Impacting Comparability of Our Financial Results for a discussion of why our cash flows and capital expenditures may not be comparable, either from period to period or going forward.

Working Capital Surplus (Deficit). Working capital is the amount by which current assets exceed current liabilities and is a measure of our ability to pay our liabilities as they become due. During periods of growth capital expenditures, we experience working capital deficits when we fund construction expenditures out of working capital until they are permanently financed. Our working capital is also influenced by current risk management assets and liabilities due to fair market value changes in our derivative positions being reflected on our balance sheet. These represent our expectations for the settlement of risk management rights and obligations over the next twelve months, and so must be viewed differently from trade receivables and payables which settle over a much shorter span of time. Risk management assets and liabilities affect working capital. When our derivative positions are settled, we expect an offsetting physical transaction, and, as a result, we do not expect these assets and liabilities to affect our ability to pay bills as they come due.

Our working capital deficit decreased by $18,333,000 from December 31, 2005 to December 31, 2006 primarily due to the following:

- a $7,665,000 decrease in current liabilities resulting from a reduction in the valuation of our risk management contracts due to lower index NGL prices offset by increases in interest rates;
- a $5,025,000 increase in current assets resulting from an increase in accounts receivable due to the timing of cash receipts;
- a $5,453,000 increase in current assets resulting from an increase in cash and cash equivalents primarily due to the termination of interest rate swaps;
- a $3,100,000 decrease in related party payables due to the timing of payments; and partially offset by
- an increase in other current liabilities of $3,147,000 primarily due to an increase in interest payable, as we now pay interest semi-annually on all senior notes.

Cash Flows from Operating Activities. Net cash flows provided by operating activities increased $6,816,000, or 18 percent, for the year ended December 31, 2006 compared to the corresponding period in 2005. The primary reason for the increased cash flow was increased margin contributions from the completion of our Regency Intrastate Enhancement Project, the installation of additional capacity on our gathering and processing systems and our acquisition of TexStar. The remaining improvement was attributable to the termination of interest rate swaps in June and December 2006. We terminated the interest rate swap because in the fourth quarter of 2006 we refinanced the majority of our variable interest rate debt with fixed rate, 8.375 percent senior notes due in 2013. These increases in cash flows from operations were partially offset by higher interest costs primarily due to increased borrowings, the payment of management services contract termination fees, the payment of transaction fees related to our TexStar acquisition and losses on the refinancing of credit agreements.

Net cash provided by operating activities increased to $37,340,000 for the year ended December 31, 2005 compared with $28,090,000 for the combined year ended December 31, 2004. The increase was due in part to increased through-put volumes from the Transportation segment and north Louisiana region of the Gathering and Processing segment. The increased price levels for NGLs increased our cash flows from operations, but these increases were matched by cash outflows from our risk management activities, designed to stabilize our cash flows. Also contributing to the increase was the inclusion of operations from TexStar in the Gathering and Processing segment in December 2005. The increase in cash flows from operations was partially offset by an increase in cash interest paid of $10,531,000, as the amount of our debt financing significantly increased following our acquisition of TexStar, the HM Capital Transaction and our Regency Intrastate Enhancement Project.

For all periods, we used our cash flows from operating activities together with borrowings under our revolving credit facility for our working capital requirements, which include operation and maintenance expenses, maintenance capital expenditures and repayment of working capital borrowings. From time to time during each period, the timing of receipts and disbursements required us to borrow under our revolving credit facility. The maximum amounts of revolving line of credit borrowings outstanding during the years ended December 31, 2006 and 2005 were $112,600,000 and $50,000,000, respectively.

Cash Flows from Investing Activities. Net cash flows used in investing activities decreased $56,313,000, or 20 percent, for the year ended December 31, 2006 compared to the year ended December 31, 2005. The decrease was primarily due to lower levels of spending on asset purchases and growth and maintenance capital expenditures, discussed in Capital Requirements.

Our cash flows used in investing activities increased $64,764,000 for the year ended December 31, 2005 as compared to the combined year ended December 31, 2004 primarily due to capital expenditures for our Regency Intrastate Enhancement Project and maintenance capital expenditures.

Cash Flows from Financing Activities. Net cash flows provided by financing activities decreased $58,002,000, or 24 percent, for the year ended December 31, 2006 compared to the corresponding period in 2005 primarily due to (1) $42,975,000 net borrowings under our credit facility to finance our TexStar acquisition, organic growth projects, working capital requirements and to amend and restate our credit facility, (2) $37,144,000 of partner distributions made in 2006 not made in 2005; and (3) a decrease in member interest contributions of $68,214,000 as HM Capital Investors infused $72,000,000 into us and TexStar in 2005 for growth capital projects.

Net cash flows from financing activities increased from the combined year ended December 31, 2004 to December 31, 2005 by $54,054,000 primarily due to increased member interest contributions of $57,500,000 as HM Capital Investors infused $72,000,000 into us and TexStar in 2005 for growth capital projects.

CAPITAL REQUIREMENTS

We categorize our capital expenditures as either:

- Growth capital expenditures, which are made to acquire additional assets to increase our business, to expand and upgrade existing systems and facilities or to construct or acquire similar systems or facilities; or
- Maintenance capital expenditures, which are made to replace partially or fully depreciated assets, to maintain the existing operating capacity of our assets and to extend their useful lives or to maintain existing system volumes and related cash flows.

Growth Capital Expenditures. In the year ended December 31, 2006, we incurred $121,825,000 of growth capital expenditures. Growth capital expenditures for the year ended December 31, 2006 primarily relate to the completion of our Regency Intrastate Enhancement Project, projects completed by TexStar both before and after we acquired it, two new 200 MMcf/d dewpoint control facilities, additional gas compressors, a scheduled loop of a western segment of our intrastate pipeline, expansion of north Louisiana gathering and processing system and 6 miles of 12-inch pipeline in Lincoln Parish, Louisiana.

Our 2007 growth budget includes approximately $55,000,000 of currently identified organic growth capital expenditures. These growth capital expenditures are for more than 25 projects, of which the most significant are the following:

Re-build and activate existing nitrogen rejection unit at our Eustace Processing Plant;

Constructing 31 miles of 12 inch diameter pipeline in south Texas;

Electrification and adding an acid gas injection well at our Tilden Processing Plant; and

Adding an acid gas injection well at our Waha Processing Plant to provide flexibility to the level of sulfur that can be processed.

We expect to fund these growth capital expenditures out of borrowings under our existing credit agreement. We continually review opportunities for both organic growth projects and acquisitions that will enhance our financial performance. Since we distribute our available cash to our unitholders, we depend on borrowings under our credit facility and the incurrence of debt and equity securities to finance any future growth capital expenditures or acquisitions.

Maintenance Capital Expenditures. In the year ended December 31, 2006, we incurred $16,433,000 of maintenance capital expenditures, approximately $8,200,000 of which was spent by TexStar to refurbish the Eustace Plant prior to our acquisition. Maintenance capital expenditures primarily consist of compressor and plant overhauls, as well as new well connects to our gathering systems, which replace volumes from naturally occurring depletion of wells already connected. Our 2007 budget for maintenance capital expenditures is $10,200,000.

Fourth Amended and Restated Credit Agreement

In connection with our acquisition of TexStar, RGS, amended and restated its $470,000,000 credit agreement, increasing the facility to $850,000,000 consisting of $600,000,000 in term loans and $250,000,000 in a revolving credit facility. The availability for letters of credit was increased to $100,000,000. RGS has 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, provided that no event of default has occurred or would result due to such increase, and all other additional conditions for the increase of the commitments set forth in the fourth amended and restated credit agreement, or the credit facility, have been met.

RGS obligations under the credit facility are secured by substantially all of the assets of RGS and its subsidiaries and are guaranteed by the Partnership and each such subsidiary. The revolving loans under the facility will mature in five years, and the term loans thereunder will mature in seven years.

Interest on term loan borrowings under the credit facility will be calculated, at the option of RGS, at either: (a) a base rate plus an applicable margin of 1.50 percent per annum or (b) an adjusted LIBOR rate plus an applicable margin of 2.50 percent per annum. Interest on revolving loans thereunder will be calculated, at the option of RGS, at either: (a) a base rate plus an applicable margin of 1.00 percent per annum or (b) an adjusted LIBOR rate plus an applicable margin of 2.00 percent per annum. RGS must pay (i) a commitment fee equal to 0.50 percent per annum of the unused portion of the revolving loan commitments, (ii) a participation fee for each revolving lender participating in letters of credit equal to 2.25 percent per annum of the average daily amount of such lender s letter of credit exposure, and (iii) a fronting fee to the issuing bank of letters of credit equal to 0.125 percent per annum of the average daily amount of the letter of credit exposure.

The credit facility contains financial covenants requiring RGS and its subsidiaries to maintain debt to consolidated EBITDA and consolidated EBITDA to interest expense within certain threshold ratios. At December 31, 2006, RGS and its subsidiaries were in compliance with these covenants.

The credit facility restricts the ability of RGS to pay dividends and distributions other than reimbursements of us for expenses and payment of dividends to us to the extent of our determination of available cash under the partnership agreement (so long as no default or event of default has occurred or is continuing). The credit facility also contains various other covenants.

The outstanding balances of term debt and revolver debt under the credit facility bear interest at either LIBOR plus margin or at Alternative Base Rate (equivalent to the US prime lending rate) plus margin, or a combination of both. The weighted average interest rates for the revolving and term loan facilities, including interest rate swap settlements, commitment fees, and amortization of debt issuance costs were 7.70 percent for the year ended December 31, 2006.

Senior Notes

On December 12, 2006, the Partnership and Regency Energy Finance Corp., a wholly owned subsidiary of RGS, issued $550,000,000 in the principal amount of senior notes that mature on December 15, 2013 in a private placement (senior notes). 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, and are guaranteed by all of our subsidiaries.

The senior notes and the guarantees will be unsecured and will rank equally with all of our and the guarantors existing and future unsubordinated obligations. The senior notes and the guarantees will be senior in right of payment to any of our and the guarantors future obligations that are, by their terms, expressly subordinated in right of payment to the notes and the guarantees. The senior notes and the guarantees will be effectively subordinated to our and the guarantors secured obligations, including our credit facility, to the extent of the value of the assets securing such obligations.

The notes are initially guaranteed by each of the Partnership s current subsidiaries (the Guarantors), except Finance Corp. These note guarantees are the joint and several obligations of the Guarantors. A Guarantor may not sell or otherwise dispose of all or substantially all of its properties or assets if such sale would cause a default under the terms of the senior notes. Events of default include nonpayment of principal or interest when due; failure to make a change of control offer (explained below); failure to comply with reporting requirements according to SEC rules and regulations; and defaults on the payment of obligations under other mortgages or indentures.

We may redeem the senior notes, in whole or in part, at any time on or after December 15, 2010, at a redemption price equal to 100 percent of the principal amount thereof, plus a premium declining ratably to par and accrued and unpaid interest and liquidated damages, if any, to the redemption date. At any time before December 15, 2010, we may redeem some or all of the notes at a redemption price equal to 100 percent of the principal amount plus a make-whole premium, plus accrued and unpaid interest and liquidated damages, if any, to the redemption date. At any time before December 15, 2009, we may redeem up to 35 percent of the aggregate principal amount of the notes issued under the indenture with the net cash proceeds of one or more qualified equity offerings at a redemption price equal to 108.375 percent of the principal amount of the notes to be redeemed, plus accrued and unpaid interest and liquidated damages, if any, to the redemption date; provided that: (i) at least 65 percent of the aggregate principal amount of the notes remains outstanding immediately after the occurrence of such redemption; and (ii) such redemption occurs within 90 days of the date of the closing of any such qualified equity offering.

Upon a change of control, each holder of notes will be entitled to require us to purchase all or a portion of its notes at a purchase price equal to 101 percent of the principal amount thereof, plus accrued and unpaid interest and liquidated damages, if any, to the date of purchase. Our ability to purchase the notes upon a change of control will be limited by the terms of our debt agreements, including our credit facility.

The senior notes contain covenants that, among other things, limit our ability and the ability of certain of our subsidiaries to: (i) incur additional indebtedness; (ii) pay distributions on, or repurchase or redeem equity interests; (iii) make certain investments; (iv) incur liens; (v) enter into certain types of transactions with our affiliates; and (vi) sell assets or consolidate or merge with or into other companies. If the senior notes achieve investment grade ratings by both Moody s and S&P and no default or event of default has occurred and is continuing, we will no longer be subject to many of the foregoing covenants.

The senior notes include registration rights whereby we agreed to:

file a registration statement within 150 days of the issue date, enabling holders to exchange the privately placed notes for publicly registered exchange notes with substantially the same terms;

use our commercially reasonable efforts to cause the registration statement to become effective within 310 days of the issue date;

use our commercially reasonable efforts to issue the exchange notes within 30 business days after the registration statement has become effective, unless prohibited by law or SEC policy; and

file a shelf registration statement for the resale of the senior notes if we cannot consummate the exchange offer within the time period listed above and in certain other circumstances.

We have agreed to pay liquidated damages in the form of additional interest payments to holders of the senior notes under certain circumstances if we do not comply with our obligations under the registration rights agreement.

Letters of Credit. At December 31, 2006, we had outstanding letters of credit totaling $5,183,000. The total fees for letters of credit accrue at an annual rate of 2.125 percent, which is applied to the daily amount of letters of credit exposure.

Off-Balance Sheet Transactions and Guarantees. We have no off-balance sheet transactions or obligations.

Total Contractual Cash Obligations. The following table summarizes our total contractual cash obligations as of December 31, 2006.

		Payments Due by Period			
Contractual Obligations	**Total**	**2007**	**2008-2009**	**2010-2011**	**Thereafter**
			(In thousands)		
Long-term debt (including interest)(1)	$ 1,025,387	$ 55,644	$ 111,288	$ 216,330	$ 642,125
Operating leases	1,570	653	759	158	
Purchase obligations	38,669	38,669			
Total(2)	$ 1,065,626	$ 94,966	$ 112,047	$ 216,488	$ 642,125

(1) Assumes a constant current LIBOR interest rate of 5.3279 percent plus the applicable margin on our $50,000,000 term note and revolver. Our senior notes of $550,000,000 bear a fixed interest rate of 8.375 percent.

(2) Excludes physical and financial purchases of natural gas, NGLs, and other energy commodities due to the nature of both the price and volume components of such purchases, which vary on a daily or monthly basis. Additionally, we do not have contractual commitments for fixed price and/or fixed quantities of any material amount.

RECENT ACCOUNTING PRONOUNCEMENTS

In July 2006, the FASB issued FIN No. 48 Accounting for Uncertainty in Income Taxes An Interpretation of FASB Statement 109 , which clarifies the accounting for uncertainty in income taxes recognized in financial statements in accordance with FASB Statement No. 109, Accounting for Income Taxes and is effective for fiscal years beginning after December 15, 2006. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The adoption of FIN 48 is not expected to have a material impact on our consolidated results of operations, cash flows or financial position.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements , which provides guidance for using fair value to measure assets and liabilities. SFAS 157 applies whenever another standard requires (or permits) assets or liabilities to be measured at fair value. This standard does not expand the use of fair value to any new circumstances. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. We are currently evaluating the potential impacts on our financial position, results of operations or cash flows of the adoption of this standard.

In September 2006, the Securities and Exchange Commission issued Staff Accounting Bulletin No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements, (SAB 108) to address diversity in practice in quantifying financial statement misstatements. SAB 108 requires entities to quantify misstatements based on their impact on each of their financial statements and related disclosures. SAB 108, effective as of December 31, 2006, allows for a one-time transitional cumulative effect adjustment to retained earnings as of January 1, 2006 for errors that were not previously deemed material, but are material under the guidance in SAB 108. The adoption of this standard did not have a material impact on the Partnership s consolidated results of operations, cash flows or financial position.

In January 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, Including an Amendment of FASB Statement No. 115 (SFAS 159), which permits entities to measure many financial instruments and certain other assets and liabilities at fair value on an instrument-by-instrument basis. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. We are currently evaluating the potential impacts on our financial position, results of operations or cash flows of the adoption of this standard.

Item 7A. *Quantitative and Qualitative Disclosure about Market Risk*

Risk and Accounting Policies

We are exposed to market risks associated with commodity prices, counterparty credit and interest rates. Our management has established comprehensive risk management policies and procedures to monitor and manage these market risks. Our Managing General Partner is responsible for delegation of transaction authority levels, and the Risk Management Committee of our Managing General Partner is responsible for the overall management of credit risk and commodity price risk, including monitoring exposure limits. See Critical Accounting Policies and Estimates Risk Management Activities for further discussion of the accounting for derivative contracts. The Risk Management Committee receives regular briefings on positions and exposures, credit exposures and overall risk management in the context of market activities.

Commodity Price Risk

We are exposed to the impact of market fluctuations in the prices of natural gas, NGLs and other commodities as a result of our gathering, processing and marketing activities, which in the aggregate produce a naturally long position in both natural gas and NGLs. We attempt to mitigate commodity price risk exposure by matching pricing terms between our purchases and sales of commodities. To the extent that we market commodities in which pricing terms cannot be matched and there is a substantial risk of price exposure, we attempt to use financial hedges to mitigate the risk. It is our policy not to take any speculative marketing positions. In some cases, we may not be able to match pricing terms or to cover our risk to price exposure with financial hedges, and we may be exposed to commodity price risk.

Both our profitability and our cash flow are affected by volatility in prevailing natural gas and NGL prices. Natural gas and NGL prices are impacted by changes in the supply and demand for NGLs and natural gas, as well as market uncertainty. Historically, changes in the prices of heavy NGLs, such as natural gasoline, have generally correlated with changes in the price of crude oil. Adverse effects on our cash flow from reductions in natural gas and NGL product prices could adversely affect our ability to make distributions to unitholders. We manage this commodity price exposure through an integrated strategy that includes management of our contract portfolio, matching sales prices of commodities with purchases, optimization of our portfolio by monitoring basis and other price differentials in our areas of operations, and the use of derivative contracts.

We are a net seller of NGLs, condensate and natural gas, and as such our financial results are exposed to fluctuations in NGL pricing. We have executed swap contracts settled against crude oil, ethane, propane,

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butane and natural gasoline market prices, supplemented with crude oil put options. 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.

The following table sets forth certain information regarding our non-trading NGL swaps outstanding at December 31, 2006. The relevant index price that we pay is the monthly average of the daily closing price for deliveries of commodities into Mont Belvieu, Texas, as reported by the Oil Price Information Service (OPIS).

Period	Commodity	Notional Volume (MBbls)	We Pay	We Receive ($/gallon)	Fair Value (In thousands)	
January 2007 December 2008	Ethane	959	Index	$0.55-$0.6725	$	(792)
January 2007 December 2008	Propane	680	Index	$0.825-$1.0975		(562)
January 2007 December 2009	Butane	630	Index	$1.025-$1.27		638
January 2007 December 2008	Natural Gasoline	209	Index	$1.22-$1.565		153
January 2007 December 2009	West Texas Intermediate Crude	712	Index	$65.60-$68.38		563
Total Fair Value					$	

Credit Risk

Our purchase and resale of natural gas exposes us to credit risk, as the margin on any sale is generally a very small percentage of the total sale price. Therefore a credit loss can be very large relative to our overall profitability. We attempt to ensure that we issue credit only to credit-worthy counterparties and that in appropriate circumstances any such extension of credit is backed by adequate collateral such as a letter of credit or parental guarantees.

In January 2005, one of our customers filed for Chapter 11 reorganization under U.S. bankruptcy law. The customer operates a merchant power plant, for which we provide firm transportation of natural gas. Under the contract with the customer, the customer is obligated to make fixed payments in the amount of approximately $3,200,000 per year. The contract, which expires in mid-2012, was originally secured by a $10,000,000 letter of credit. In December 2005, in connection with other contract negotiations, the letter of credit was reduced to $3,300,000 and we accepted a parent guarantee in the amount of $6,700,000. The customer has accepted the firm transportation contract in bankruptcy. The customer s plan of reorganization has been confirmed by the bankruptcy court and the customer has since emerged from bankruptcy protection. At December 31, 2006, the customer was current in its payment obligations.

Interest Rate Risk

In June and December 2006, we early terminated our interest rate swaps with notional amounts of $200,000,000 that converted amounts outstanding under our credit agreement from a floating rate of interest to the fixed rate of interest from January 1, 2007 until March 31, 2009. As a result, we are exposed to variable interest rate risk as a result of borrowings under our existing credit facility. As of December 31, 2006, we had $114,700,000 of outstanding long-term balances exposed to variable interest rate risk. An increase of 100 basis points in the LIBOR rate would increase our annual payment by approximately $1,100,000

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Item 8. ***Financial Statements and Supplementary Data.***

The financial statements set forth starting on page F-1 of this report are incorporated by reference.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.***

None.

Item 9A. ***Controls and Procedures.***

We maintain controls and procedures designed to ensure that information required to be disclosed in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. An evaluation was performed under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of our Managing General Partner, of the effectiveness of the design and operation of our disclosure controls and procedures (as such terms are defined in Rule 13a-15(e) and 15d-15(e) of the Exchange Act). Based on that evaluation, management, including the Chief Executive Officer and Chief Financial Officer of our Managing General Partner, concluded that our disclosure controls and procedures were effective as of December 31, 2006 to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC s rules and forms.

Our management does not expect that our disclosure controls and procedures will prevent all errors. The design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all of our disclosure control issues have been detected. These inherent limitations include the realties that judgments in decision-making can be faulty and that breakdowns can occur because of simple errors or mistakes. The design of any system of controls also is based in part on certain assumptions about the likelihood of future events. Therefore, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Our disclosure controls and procedures are designed to provide such reasonable assurances of achieving our desired control objectives and the Chief Executive Officer and the Chief Financial Officer of our general partner have concluded, as of December 31, 2006, that our disclosure controls and procedures are effective in achieving that level of reasonable assurance.

Management has acknowledged that it is responsible for establishing and maintaining a system of disclosure controls and procedures for us. We have designed those disclosure controls and procedures to ensure that material information relating to us, including our consolidated subsidiaries, is made known to management by others within those entities. We have evaluated the effectiveness of our disclosure controls and procedures, as of the end of fiscal year 2006, and concluded that they are effective.

We are not yet subject to Section 404 of the Sarbanes-Oxley Act which, when applicable, will require us to include Management s Annual Report on Internal Control Over Financial Reporting and an Attestation Report of Independent Registered Public Accounting Firms in its Annual Report on Form 10-K. Under the applicable rules of the SEC, Section 404 will not apply to the Partnership until the due date of our annual report for the year ending December 31, 2007.

In anticipation of becoming subject to the provisions of Section 404 of the Sarbanes-Oxley Act of 2002, we initiated in early 2005 a program of documentation, implementation and testing of internal control over financial reporting.

This program will continue through this year, culminating with our initial Section 404 certification and attestation in early 2008. While our independent registered public accounting firm has not attested to or reported on our internal control over financial reporting as of the end of fiscal 2006, we have evaluated the effectiveness of our system of internal control over financial reporting, as well as changes therein, in compliance with Rule 13a-15 of the SEC s rules under the Securities Exchange Act and have filed the certifications with this annual report required by Rule 13a-14.

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In the course of that evaluation, we found no fraud, whether or not material, that involved management or other employees who have a significant role in our internal control over financial reporting and no material weaknesses. To the extent that we discovered any matter in the design or operation of our system of internal control over financial reporting that might be considered to be a significant deficiency or a material weakness, whether or not considered reasonably likely to adversely affect our ability to record, process, summarize and report financial information, we reported that matter to our independent registered public accounting firm and to the audit committee of our board of directors.

Item 9B. ***Other Information.***

None.

Part III

Item 10. ***Directors, Executive Officers and Corporate Governance***

Management

Regency GP LP is our General Partner. Our General Partner manages and directs all of our activities. The activities of the General Partner are managed and directed by its general partner, Regency GP LLC, or the Managing General Partner. Our officers and directors are officers and directors of the Managing General Partner. The owners of the Managing General Partner may appoint up to ten persons to serve on the Board of Directors of the Managing General Partner. Although there is no requirement that he do so, the President and Chief Executive Officer of the Managing General Partner is currently a director of the Managing General Partner and serves as Chairman of the Board of Directors.

Our Board of Directors was, until the resignation of Robert W. Shower in February 2007 for reasons of health, comprised of its Chairman (the President and Chief Executive Officer of the Managing General Partner), three persons who qualify as independent under The NASDAQ Stock Market, Inc., or NASDAQ, standards for audit committee members and six persons who were either appointed by the sole member of the Managing General Partner or elected by the other members of the Board of Directors. As a result of Mr. Shower s resignation, there are currently only two directors who qualify as independent.

Following our notice to The Nasdaq Stock Market of Mr. Shower s resignation, we received a Nasdaq Staff Deficiency Letter on February 15, 2007 indicating that we now fail to comply with Marketplace rule 4350 relating to the composition of our Audit Committee. Compliance is required for continued listing on The Nasdaq Stock Market, but, in accordance with Marketplace rule 4350(d)(4), the Market has provided a cure period of one year within which to reestablish compliance. We are currently in the process of identifying a suitable nominee.

Corporate Governance

The Board has adopted Corporate Governance Guidelines to assist it in the exercise of its responsibilities to provide effective governance over our affairs for the benefit of our unitholders. In addition, we have adopted a Code of Business Conduct, which sets forth legal and ethical standards of conduct for all our officers, directors and employees. Specific provisions are applicable to the principal executive officer, principal financial officer, principal accounting officer and controller, or those persons performing similar functions, of our Managing General Partner. The Corporate Governance Guidelines, the Code of Business Conduct and the charters of our audit, compensation, nominating and executive committees are available on our website at www.regencygas.com. Amendments to, or waivers from, the

Code of Business Conduct will also be available on our website and reported as may be required under SEC rules; however, any technical, administrative or other non-substantive amendments to the Code of Business Conduct may not be posted. Please note that the preceding Internet address is for information purposes only and is not intended to be a hyperlink. Accordingly, no information found or provided at that Internet addresses or at our website in general is intended or deemed to be incorporated by reference herein.

Conflicts Committee. The Board of Directors appoints members of the Board to serve on the Conflicts Committee with the authority to review specific matters for which the Board of Directors believes there may be a conflict of interest in order to determine if the resolution of such conflict proposed by the Managing General Partner is fair and reasonable to us and our common unitholders. Any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by the General Partner, the Managing General Partner or its Board of Directors of any duties they may owe us or the common unitholders. The current members of the Conflicts Committee are,with Mr. Shower s resignation as a director, A. Dean Fuller (Chairman) and J. Otis Winters. The Conflicts Committee met 12 times in considering and approving the TexStar acquisition.

Audit Committee. The Board of Directors has established an Audit Committee in accordance with the Exchange Act. The Board of Directors initially appointed five directors as members of the Audit Committee, including three individuals who are independent under the NASDAQ s standards for audit committee members to serve on its Audit Committee. In addition, the Board had determined that at least one member of the Audit Committee (Robert W. Shower) had such accounting or related financial management expertise sufficient to qualify such person as the audit committee financial expert in accordance with Item 401 of Regulation S-K. (While no formal determination has been made, management believes that Mr. Otis Winters is similarly qualified.) In February 2007, the two members that did not qualify as independent directors resigned from the Audit Committee in compliance with applicable rules of the SEC and the NASDAQ Marketplace Rules.

The Audit Committee meets on a regularly scheduled basis with our independent accountants at least four times each year and is available to meet at their request. The Audit Committee has the authority and responsibility to review our external financial reporting, to review our procedures for internal auditing and the adequacy of our internal accounting controls, to consider the qualifications and independence of our independent accountants, to engage and resolve disputes with our independent accountants, including the letter of engagement and statement of fees relating to the scope of the annual audit work and special audit work which may be recommended or required by the independent accountants, and to engage the services of any other advisors and accountants as the Audit Committee deems advisable. The Audit Committee reviews and discusses the audited financial statements with management, discusses with our independent auditors matters required to be discussed by SAS 61 (Communications with Audit Committees), and makes recommendations to the Board of Directors relating to our audited financial statements.

The Audit Committee is authorized to recommend periodically to the Board of Directors any changes or modifications to its charter that the Audit Committee believes may be required.

Compensation and Nominating Committees. Although we are not required under NASDAQ Marketplace rules to appoint a Compensation Committee or a Nominating/Corporate Governance Committee because we are a limited partnership, the Board of Directors of the Managing General Partner has established a Compensation Committee to establish standards and make recommendations concerning the compensation of our officers and directors. In addition, the Compensation Committee determines and establishes the standards for any awards to our employees and officers, including the performance standards or other restrictions pertaining to the vesting of any such awards, under our existing Long Term Incentive Plan, as well as any other equity compensation plans adopted by our common unitholders. The Compensation Committee is composed of Jason H. Downie (Chairman), Joe Colonnetta and J. Otis Winters, none of whom is an officer or employee of us or the Managing General Partner. For further information, please read Item 11 Executive Compensation.

The Board of Directors has also appointed a Nominating Committee to assist the Board and the member of our Managing General Partner by identifying and recommending to the Board of Directors individuals qualified to become Board members, to recommend to the Board director nominees for each committee of the Board and to advise the Board about and recommend to the Board appropriate corporate governance practices. The Nominating Committee is composed of Joe Colonnetta (Chairman), Jason H. Downie and J. Edward Herring. Matters relating to the election of Directors or to Corporate Governance are addressed to and determined by the full Board of Directors.

Meetings of Non-Management Directors and Communication with Directors

As a limited partnership, our Managing General Partner is required to maintain a sufficient number of independent directors (as defined by the NASDAQ Marketplace rules) for it to satisfy those rules regarding membership of independent directors on the audit committee of its board of directors. Our independent directors are required by those rules to meet in executive session at least twice each year. In practice, they meet in executive session at most regularly scheduled meetings of the board. The position of the presiding director at these meetings is rotated among the independent directors. A. Dean Fuller is the presiding director for the meetings of the independent directors to be held prior to the 2008 Annual Meeting of the Board. Interested parties may make their concerns known to the independent directors directly and anonymously by writing to the Chairman of the Audit Committee, Regency GP LLC, 1700 Pacific Avenue, Suite 2900, Dallas, Texas 75201.

Directors and Executive Officers

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

Name	Age	Position with Regency GP LLC
James W. Hunt(1)(4)(5)	63	Chairman of the Board, President and Chief Executive Officer
Michael L. Williams	47	Executive Vice President and Chief Operating Officer
Stephen L. Arata	41	Executive Vice President and Chief Financial Officer
William E. Joor III	67	Executive Vice President, Chief Legal and Administrative Officer and Secretary
Charles M. Davis, Jr.(7)	45	Senior Vice President-Corporate Development
Richard D. Moncrief	48	Senior Vice President, Gas Supply and Business Development
Lawrence B. Connors	56	Vice President, Finance and Chief Accounting Officer
Alvin Suggs	54	Senior Vice President and General Counsel
Houston C. Ross III(8)	37	Vice President, Financial Analysis and Planning
Christofer Rozzell(8)	31	Vice President, Corporate Development
Ramon Suarez, Jr.(8)	44	Vice President, Treasurer
Joe Colonnetta(1)(4)(6)	45	Director
Jason H. Downie(1)(4)(5)(6)	36	Director
A. Dean Fuller(2)(3)	59	Director
Jack D. Furst	48	Director
J. Edward Herring(6)	37	Director
Robert D. Kincaid	46	Director
Gary W. Luce(5)	46	Director
J. Otis Winters(2)(3)(4)	74	Director

(1) Member of the Executive Committee. Mr. Colonnetta is chairman of this committee.

(2) Member of the Audit Committee.

(3) Member of Conflicts Committee. Mr. Fuller is chairman of this committee.

(4) Member of Compensation Committee. Mr. Downie is chairman of this committee. Mr. Hunt is an exofficio member.

(5) Member of Risk Management Committee. Mr. Luce is chairman of this committee. Mr. Hunt is an exofficio member.

(6) Member of Nominating Committee. Mr. Colonnetta is chairman of this committee.

(7) Mr. Davis was elected an officer on March 21, 2006 and commenced employment in March 2006.

(8) Elected March 22, 2007.

Our operating partnership, Regency Gas Services LP, is operated by its general partner, Regency OLP GP LLC. The following are the officers of the latter:

James W. Hunt	President
Michael L. Williams	Vice President
Stephen L. Arata	Vice President
William E. Joor III	Vice President and Secretary
Richard D. Moncrief	Vice President
Lawrence B. Connors	Vice President
Alvin Suggs	Vice President
Durell J. Johnson	Vice President
James A. Scott	Vice President
Martin Anthony	Vice President
Jacque L. Wolf	Vice President
Ramon Suarez, Jr.	Treasurer

James W. Hunt was elected Chairman of the Board of Directors of Regency GP LLC and Regency Gas Services in November 2005. Mr. Hunt has served as President and Chief Executive Officer of Regency GP LLC from September 2005 to present. Mr. Hunt has, since his election effective December 1, 2004, served as President, Chief Executive Officer and Director of Regency Gas Services LLC. From 1978 until January 1981, Mr. Hunt served as President and Chief Executive Officer of Diamond M Company, a major offshore drilling company and the predecessor of Diamond Offshore Company. From 1981 through 1987, he served as Chairman and Chief Executive Officer of Cenergy Corporation, a NYSE listed oil and gas exploration, production and pipeline company. During the period from 1987 to 1989, Mr. Hunt was an independent financial consultant. From 1989 until December 2004, Mr. Hunt was engaged in energy investment banking, three years as head of the Houston office of Lehman Brothers Incorporated and most recently as head of the U.S. Energy Group of UBS Securities LLC. Mr. Hunt is an attorney and member of the State Bar of Texas.

Michael L. Williams, P.E., was elected Executive Vice President and Chief Operating Officer of Regency GP LLC in September 2005. From December 2004 to the present, Mr. Williams served as Executive Vice President and Chief Operating Officer of Regency Gas Services LLC. Mr. Williams served as Vice President of Engineering and Operations from October 2002 through September 2004 heading up operations and engineering at Energy Transfer Partners, L.P. Mr. Williams also served as Vice President of Engineering and Operations for Aquila Inc. from 2000 through September 2002 where he was responsible for the Operation and Engineering of Aquila s gas gathering, processing, fractionation, and storage assets.

Stephen L. Arata was elected Executive Vice President and Chief Financial Officer of Regency GP LLC in September 2005. From June 2005 to the present, Mr. Arata served as Executive Vice President and Chief Financial Officer of

Regency Gas Services LLC. From September 1996 to June 2005, Mr. Arata worked for UBS Investment Bank, covering the power and pipeline sectors; he was Executive Director from 2000 through June 2005. Prior to UBS, Mr. Arata worked for Deloitte Consulting, focusing on the energy sector.

William E. Joor III was elected Executive Vice President, Chief Legal and Administrative Officer and Secretary of Regency GP LLC in September 2005. Mr. Joor has, since his election effective January 1, 2005, served as Executive Vice President, Chief Legal and Administrative Officer and Secretary of Regency Gas Services LLC. From May 1966 through December 1973, Mr. Joor was associated with, and from then until

December 31, 2004 was a partner of, Vinson & Elkins LLP. Mr. Joor s area of specialization was the law of corporate finance and mergers and acquisitions with particular emphasis in the energy sector.

Charles M. Davis, Jr. was elected Senior Vice President Corporate Development for Regency GP LLC in March 2006. From September 2004 to February 2005, Mr. Davis was Managing Director and Head of Mergers and Acquisitions for Challenger Capital Group Ltd. From July 2002 until September 2004, Mr. Davis was a Managing Director in the Energy and Power Group of UBS Investment Bank. From March 1992 until August 2002, Mr. Davis was a Managing Director in the Global Energy and Power Group of Merrill Lynch. Prior to Merrill, Mr. Davis worked in the Energy Groups of The First Boston Corporation and McKinsey & Co. Mr. Davis has over 20 years experience with mergers and acquisitions as well as financing in the pipeline industry.

Richard D. Moncrief was elected Senior Vice President of Gas Supply and Business Development in April 2006. Mr. Moncrief was most recently associated with Sid Richardson Energy Services, of Fort Worth, Texas, where-until that company s recent sale-he was Vice President, Business Development, and more recently Vice President, Engineering & Business Development. As such, his responsibilities included all business development activities (acquisitions, divestitures, major system expansions and asset optimization projects) for the company s 4,000 miles of gathering system in the Permian Basin area of west Texas and southeast New Mexico. He previously held management positions at Koch Midstream Services Company and at Delhi Gas Pipeline Corporation. After graduation with a B.S. in Petroleum Engineering at Texas A&M in 1981, he worked at Getty Oil Company and TXO Production Company before joining Delhi.

Lawrence B. Connors was elected Vice President of Finance and Chief Accounting Officer of Regency GP LLC in September 2005. From December 2004 to the present, Mr. Connors served as Vice President, Finance and Chief Accounting Officer of Regency Gas Services LLC. From June 2003 through November 2004, Mr. Connors served as Controller of Regency Gas Services LLC. From August 2000 through November 2001, Mr. Connors was an independent accounting and financial consultant. From 2001 through May 2003 Mr. Connors was a Registered Representative with Foster Financial Group. From 1996 through July 2000, Mr. Connors was the Controller and Chief Accounting Officer of Central and South West Corporation, or CSW; he had managerial responsibilities at three CSW operating companies and CSW Services. Prior to his employment at CSW, he was with Arthur Andersen working with energy and health care audit clients. Mr. Connors is a Certified Public Accountant.

Alvin Suggs was elected Senior Vice President and General Counsel of Regency GP LLC in March 2007. From June 2005 to March 2007, Mr. Suggs served as Vice President and General Counsel of Regency Gas Services LLC. From June 2003 to June 2005, Mr. Suggs engaged in the private practice of law representing clients in the energy sector, first as a sole practitioner and, after June 2004, with Thompson & Knight, LLP. Mr. Suggs served as Vice President and Associate General Counsel with El Paso Energy Corporation and General Counsel of El Paso Field Services, L.P. from September 1999 through June 2003. Mr. Suggs served as Senior Counsel to El Paso Field Services, L.P. and El Paso Energy Marketing, L.P. from September 1997 to September 1999, and from 1987 to 1999 he served Texas Oil & Gas Corp., American Oil and Gas Corporation and KN Energy, Inc. in various capacities from Counsel to Assistant General Counsel. Prior to that service, Mr. Suggs was in private practice of law for five years, and also served as Assistant District Attorney for the Fifth Circuit Court District in Mississippi in 1978.

Houston C. Ross III was elected Vice President of Financial Analysis and Planning of Regency GP LLC in March 2007. From February 2004 until the present, Mr. Ross served as Director of Financial Analysis and Planning for Regency Gas Services LLC. From February 2003 until February 2004, Mr. Ross worked for Energy, Economic, and Environmental Consultants, Inc., as a Senior Economic Analyst specializing in natural gas royalty litigation support. From May 2002 until February 2003, Mr. Ross was an independent consultant. From May 1998 until May 2002, Mr. Ross worked for Engage Energy US LP and its corporate successor, El Paso Merchant Energy, trading electricity in the US markets from May 1999 until May 2002. Mr. Ross graduated from Rice University in 1998 with a BS in

Mechanical Engineering.

Christofer D. Rozzell was elected Vice President of Corporate Development of Regency GP LLC in March 2007. From June 2005 to the present, Mr. Rozzell served in various roles at Regency GP LLC, most

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recently as Director of Corporate Development. From May 2001 to May 2005, Mr. Rozzell held managerial positions in the strategic planning and enterprise risk groups of TXU Corp. Prior to TXU Corp., Mr. Rozzell worked in the investment Banking Division of Bear, Stearns & Co. Inc., focusing on mergers and acquisitions advisory and financings across multiple industries.

Ramon Suarez, Jr. was elected Vice President, Treasurer of Regency GP LLC in March 2007. From February 2006 to the present, Mr. Suarez was Director of Treasury for Regency GP LLC. Mr. Suarez worked for CompUSA as Director of Corporate Finance from March 1999 to December 2005. Prior to March 1999, Mr. Suarez worked for Raytheon as a Director of Finance and was involved with the acquisition and merger of four defense contracting companies. Mr. Suarez has over 21 years of financial experience.

Joe Colonnetta was elected to the Board of Directors of Regency GP LLC in September 2005 and served as Chairman of the Board of Directors until November 2005. From December 2004 to the present, Mr. Colonnetta has served as a director of Regency Gas Services LLC, including service as Chairman of the Board until November 2005. Mr. Colonnetta is a partner at HM Capital. Mr. Colonnetta joined HM Capital in 1998. Prior to joining HM Capital, Mr. Colonnetta was a partner with Metropoulos and Co., an affiliate of HM Capital. Mr. Colonnetta is also Chairman of the Board of Directors of BlackBrush Oil & Gas, and he serves on the Board of Directors of Swift & Company.

Jason H. Downie was elected to the Board of Directors of Regency GP LLC in September 2005. From December 2004 to the present, Mr. Downie has served as a director of Regency Gas Services LLC. Mr. Downie is a partner of HM Capital and has been with the firm since September 2000. From June 1999 to August 2000, Mr. Downie was an associate at Rice Sangalis Toole & Wilson, a mezzanine private equity firm based in Houston, Texas, and from June 1992 through June 1997, Mr. Downie served in various capacities with Donaldson, Lufkin & Jenrette in New York, lastly as an Associate Position Trader in their Capital Markets Group. From June 1997 to June 1999, Mr. Downie attended the McCombs School of Business at the University of Texas. Mr. Downie also serves on the Board of Directors of BlackBrush Oil & Gas.

A. Dean Fuller was elected to the Board of Directors of Regency GP LLC on November 14, 2005. Having sold in 1993 a company he co-founded, Mr. Fuller become President and Chief Executive Officer of Transok, Inc., the natural gas pipeline subsidiary of Central and South West Corporation, until its sale in 1996. Mr. Fuller continued to manage the fuels and gas marketing function of CSW until late 2000 at which time he became Senior Vice President of the midstream business of Aquila, Inc. At the time of the acquisition of Aquila s midstream business by Energy Transfer, Mr. Fuller continued to manage those assets as Senior Vice President, and served as President of Oasis Pipeline Company after its acquisition by Energy Transfer. Mr. Fuller resigned his positions with Energy Transfer in August 2004.

Jack D. Furst was elected to the Board of Directors of Regency GP LLC on December 8, 2005. Mr. Furst is a partner with HM Capital and has been with the firm since its formation in 1989. From 1987 to 1989, Mr. Furst served as a vice president and subsequently a partner of Hicks & Haas. From 1984 to 1986, Mr. Furst was a merger and acquisitions/corporate finance specialist for The First Boston Corporation in New York. Before joining First Boston, Mr. Furst was a financial consultant at Price Waterhouse. Mr. Furst received his MBA from the Graduate School of Business at the University of Texas. Mr. Furst also serves on the Board of Directors of various privately held companies.

J. Edward Herring was elected to the Board of Directors of Regency GP LLC in September 2005. From December 2004 to the present, Mr. Herring has served as a director of Regency Gas Services LLC. Mr. Herring is a partner at HM Capital and has been with the firm since 1998. From 1996 to 1998, Mr. Herring attended Harvard Business School. From 1993 to 1996, Mr. Herring was an investment banker with Goldman, Sachs & Co. Mr. Herring also serves on the Board of Directors of Swift & Company, BlackBrush Oil & Gas, Swett & Crawford and Via Systems.

Robert D. Kincaid was elected to the Board of Directors of Regency GP LLC in September 2005. From January 2005 to the present, Mr. Kincaid has served as a director of Regency Gas Services LLC. Mr. Kincaid is a co-founder, with Mr. Luce, and Managing Director of K-L Energy Partners, LLC, a private equity management firm formed in April 2004 to focus on investments in the midstream and downstream energy and power sectors. From October 1998 until December 2003, Mr. Kincaid was a principal of Haddington Ventures, LLC, another private equity management firm focused on energy-related investing. From December 2003 until March 2004, Mr. Kincaid served as a consultant to Haddington Ventures. Mr. Kincaid served as Treasurer of TPC Corporation, a firm engaged in the natural gas marketing, pipeline and storage sectors, from 1992 until its sale to PacifiCorp in April 1997. Mr. Kincaid began his career in investment banking and mezzanine fund management in Houston, Texas.

Gary W. Luce was elected to the Board of Directors of Regency GP LLC in September 2005. From January 2005 to the present, Mr. Luce has served as a director of Regency Gas Services LLC. Mr. Luce is a cofounder, with Mr. Kincaid, and has been Managing Director of K-L Energy Partners, LLC since its inception in April 2004. During the period from November 2002 until April 2004, Mr. Luce, in order to comply with the non-competition provisions of his employment agreement with Reliant Resources, Inc., acted as an independent financial consultant. Mr. Luce served as a member of the senior management team for two public energy-related companies, EOTT Energy Partners, LP from April 1994 to December 1998 and Reliant Resources, Inc. from October 1999 to November 2002. Mr. Luce also served in various capacities with McKinsey & Company, Inc., the international management-consulting firm, most recently as a downstream energy practice principal.

J. Otis Winters was elected to the Board of Directors of Regency GP LLC on November 14, 2005. The following are exemplary of Mr. Winters extensive business experience: Vice President of Warren American Oil Company from 1964 to 1965; President and a director of Educational Development Corporation from 1966 to 1973; Executive Vice President and a director of The Williams Companies, Inc. from 1973 to 1977; Executive Vice President and a director of First National Bank of Tulsa from 1978 to 1979; President and a director of Avanti Energy Corporation from 1980 to 1987; Managing Director of Mason Best Company from 1988 to 1989; Chairman, director and co-founder of The PWS Group from 1990 to 2000 and from 2001 to date Chairman and Chief Executive Officer of Oriole Oil Company. Mr. Winters has served on the board of directors of 20 publicly owned corporations, including Alton Box Board Company, AMFM, Inc., AMX Corporation, Dynegy, Inc., Liberty Bancorp., Inc., Tidel Engineering, Inc., Trident NGL, Inc. and Walden Residential Properties, Inc.

Reimbursement of Expenses of Our General Partner

Our General Partner will not receive any management fee or other compensation for its management of our partnership. Our General Partner and its affiliates will, however, be reimbursed for all expenses incurred on our behalf. These expenses include the cost of employee, officer and director compensation and benefits properly allocable to us and all other expenses necessary or appropriate to the conduct of our business and allocable to us. The partnership agreement provides that our General Partner will determine the expenses that are allocable to us. There is no limit on the amount of expenses for which our General Partner and its affiliates may be reimbursed.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires executive officers, directors and persons who beneficially own more than ten percent of a security registered under Section 12 of the Exchange Act to file initial reports of ownership and reports of changes of ownership of such security with the SEC. Copies of such reports are required to be furnished to the issuer. The common units of the Partnership were first registered under Section 12 of the Exchange Act on January 30, 2006. Based solely on a review of reports furnished to our General Partner, or written representations from reporting persons that all reportable transactions were reported, we believe that during the fiscal year ended December 31, 2006 our General Partner s officers, directors and greater than 10 percent common unitholders filed all reports they were required to file under Section 16(a).

Item 11. *Executive Compensation.*

COMPENSATION DISCUSSION AND ANALYSIS

Background

The predecessor of the Partnership, Regency Gas Services, LLC, was acquired by HMTF Regency, L.P., a limited partnership owned by the HM Capital Investors, on December 1, 2004. In connection with the acquisition, two special classes of profits interests (the Acquisition Equity Awards) of HMTF Regency, L.P. were authorized for use in attracting a team to manage the new venture. The first of these, called Class B Units, was dedicated for use in attracting officers and key employees. The second, called Class D Units, was dedicated for use in attracting outside directors. The Acquisition Equity Awards represented economic interests in HMTF Regency, L.P. only after a prior class of investment units realized specified rates of return on investment when the assets of the partnership (the member interests in Regency Gas Services LLC) were liquidated at some future date. Based on its experience in making private equity investments, HM Capital believed that equity awards offering economic rewards for success in managing the investment were customary in order to attract a highly experienced management team.

That team of officers consisted initially of James W. Hunt, President and CEO, Michael L. Williams, Executive Vice President and COO, William E. Joor III, Executive Vice President, and one member of the previous management group, Lawrence B. Connors, Vice President, Accounting & Finance. In early 2005, Stephen L. Arata, Executive Vice President and CFO, Durell J. Johnson, then Vice President, Operations, and Alvin Suggs, Vice President and General Counsel, were added to our management team.

Each member of this team, together with a few other key employees, received Acquisition Equity Awards out of the limited number of Class B unit awards that was authorized, all such authorized awards having been made by early 2005. These Acquisition Equity Awards were made to these members of the management team in accordance with their expected ability to cause Regency Gas Services to succeed, financially and operationally.

Acquisition Equity Awards of Class D Units were also granted to two individuals attracted to serve as outside directors on the board of directors of Regency Gas Services LLC. These individuals were Gary W. Luce and Robert D. Kincaid, both of whom continue to serve on the board of directors of our Managing General Partner.

At the time of our initial public offering in February 2006, each holder of Acquisition Equity Awards entered into an exchange agreement pursuant to which each such holder exchanged his or her Acquisition Equity Award for common and subordinated units of the Partnership, Regency Energy Partners LP, as well as interests in the general partner of the Partnership. The following table sets forth the number of common units and subordinated units that the chief executive officer, the chief financial officer and the other officers named in the summary compensation table received in exchange for their Acquisition Equity Awards, together with the aggregate amount of distributions paid to each of them for 2006.

Name and Title	Common Units(1)	Subordinated Units(1)	Distributions
Officers: (2)			
James W. Hunt	173,993	840,678	$ 979,036
Chairman, President and Chief Executive Officer			
Stephen L. Arata	49,712	240,194	279,619
Executive Vice President and Chief Financial Officer			
Michael L. Williams	99,425	480,387	557,769
Executive Vice President and Chief Operating Officer			
William E. Joor III	74,569	360,290	419,062
Executive Vice President, Secretary and Chief Legal and Administrative Officer			
Alvin Suggs	14,914	72,058	84,107
Senior Vice President and General Counsel			
Durell J. Johnson	14,914	72,058	84,107
Vice President Operations, Regency Gas Services LP			
Directors: (3)			
Gary W. Luce	7,715	37,278	42,370
Director			
Robert D. Kincaid	7,715	37,228	42,370
Director			

(1) In connection with the exchange of the Acquisition Equity Awards, each of these officers and directors also received indirect equity interests in Regency GP LP, the general partner of the Partnership, as follows: Mr. Hunt 3.2 percent; Mr. Arata 0.9 percent; Mr. Williams 1.6 percent; Mr. Joor 1.3 percent; Mr. Suggs 0.3 percent; Mr. Johnson 0.3 percent; Mr. Luce 0.2 percent; and Mr. Kincaid 0.2 percent. Please see Item 12 Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

(2) These Acquisition Equity Awards consisted of Class B Units of HMTF Regency, LP.

(3) These Acquisition Equity Awards consisted of Class D Units of HMTF Regency, LP.

The compensation committee of the board of directors of the Managing General Partner does not consider the Acquisition Equity Awards to be continuing compensation to these officers or directors. Consequently, neither the values attributable to the units for which the awards were exchanged nor the distributions made with respect to those units are included in the summary compensation table. The compensation committee, however, recognizes the incentive provided by the equity inherent in the Acquisition Equity Awards and takes the value of the common and subordinated units received by these directors and officers in exchange for the Acquisition Equity Awards into account in making awards under our Long Term Incentive Plan.

Overview

Compensation Goals

The principal objective of our compensation program is to attract and retain, as officers and employees, individuals of demonstrated competence, experience and leadership in our industry and in those professions required by our business and operations and who share our company s business aspirations, ethics and culture. A further objective is to provide incentives to, and to reward, our officers and key employees for positive contributions to our business and operations.

In setting the compensation programs that we utilize to recruit and retain our executive officers and key employees, we consider the following compensation objectives:

- To provide incentives and to reward performance that supports our core values, including competence, independent thought and ethical conduct;
- to provide a significant percentage of total compensation that is at-risk , or variable;
- to encourage significant equity holdings to align the interests of executive officers and key employees with those of unitholders; and
- to set compensation and incentive levels that reflect competitive market practices.

We also strive to achieve a fair balance between the compensation rewards that we perceive as necessary to remain competitive in the marketplace and fundamental fairness to our unitholders, taking into account the return on their investment.

Reward Objectives

Our compensation program is designed to reward all employees, including our executive officers, for both performance of the Partnership during the year and for individual performance of responsibilities. In measuring the performance of the Partnership, the compensation committee of the board of directors of our Managing General Partner (the compensation committee) considers the success of the Partnership in achieving its business strategies.

Under our partnership agreement, we are required to distribute all of our available cash each quarter. In general terms, our strategy is to increase the amount of cash available for distribution to each outstanding unit. Our intention is to achieve this strategy by pursuing organic growth projects that yield attractive returns and by capitalizing on accretive acquisition opportunities. As set forth more fully under Item 1 Business Business Strategies above, our specific strategies include:

- Implementing cost-effective organic growth opportunities;
- continuing to enhance profitability of our existing assets;
- pursuing accretive acquisitions of complementary assets;
- continuing to reduce our exposure to commodity price risk; and
- improving our credit ratings.

In measuring the contributions of our executive officers to the performance of the Partnership, the compensation committee considers a variety of financial metrics, including the non-GAAP financial measures of adjusted EBITDA, cash available for distribution, adjusted segment margin, and adjusted total segment margin, all of which are used by management as key measures of the Partnership s financial performance, including long-term unitholder value. The most important of these is adjusted EBITDA, which we define as net income (loss) plus net interest expense, depreciation and amortization expense, unrealized loss (gain) from risk management activities, non-cash commodity put option expirations and loss on debt refinancing. The compensation committee also considers total unitholder return, which includes both appreciation in market value of our common units and the amount of distributions paid with respect to all our outstanding units. In addition, the compensation committee takes into account the perceived achievement of the specific strategies enumerated above and individual performance.

Compensation Committee

The compensation committee is composed of three non-management members of our board of directors, two of whom are partners of HM Capital and one is an independent director. The compensation committee is directly responsible for our compensation programs, which include programs that are designed specifically for (1) our most senior executive officers, or senior officers, who include our principal executive officer (CEO), our chief financial officer (CFO) and our other executive officers named in the summary compensation table (the named executive officers or NEOs); (2) our other officers, and (3) all our other employees.

The compensation committee, as provided in its charter, is charged, among other things, with the responsibility of reviewing the Managing General Partner s executive officer compensation policies and practices. These compensation programs for executive officers consist of base salary, annual incentive bonus, and long-term incentive compensation in the form of equity-based options and restricted units, as well as other customary employment benefits. Total compensation of executive officers of the Managing General Partner and the relative emphasis of the three main components of the annual compensation are reviewed and established on an annual basis by the committee.

All deferred compensation plans for both executive officers and non-executive employees also must be approved by the compensation committee.

Compensation Advisors

In November 2005, we retained Benefits Partners, Inc., or BP, as an independent consultant with respect to compensation of senior officers and general compensation programs. In 2005 and 2006, BP provided comparative market data on compensation practices and programs based on an analysis of a broad cross-section of similarly sized energy companies, as well as a more targeted group of midstream energy peers. It also provided guidance on industry best practices. BP provided information and advice to management and the compensation committee in connection with (1) the determination of base salaries for senior officers for 2006 and (2) setting individual goals and targeted award levels for senior officers for 2006. BP did not advise either the compensation committee or management regarding the determination of individual awards for 2006 under our Long-Term Incentive Plan, or LTIP, for the senior officers.

In 2007, we retained The Hay Group, or HG, as our independent consultant to advise us regarding the compensation of officers and general compensation programs. In that regard, HG provided information with respect to comparative market data and industry best practices to the compensation committee in connection with its decisions with respect to the 2007 awards set forth in the summary compensation table below.

Compensation Mix

The decisions of the compensation committee are the result of informed judgment rather than the application of precise measurement of matters such as salary scales of our competitors or the performance of our company. As a consequence, the compensation committee evaluates the performance of our company against the various metrics set forth under Reward Objectives, is provided information regarding the salary scales of others in our industry and subjectively measures the individual performance of our officers and employees. Thus, the determinations regarding compensation made by our compensation committee are the result of the exercise of judgment based on all reasonably available information and, to that extent, are discretionary.

Each executive s current and prior compensation is considered in setting future compensation. The amount of each executive s current compensation is considered as a base against which the compensation committee makes determinations as to whether increases are necessary to retain the executive in light of competition or in order to provide continuing performance incentives. In this connection, we review the compensation practices of other companies. While we do not establish benchmarks based on compensation levels of our competitors, our compensation plan is, to this extent, influenced by the market and the companies with which we compete for leadership talent. The essential elements of our plan (*e.g.*, base salary, bonus and equity ownership) are clearly similar to the elements used by many companies. Our compensation committee believes that, by limiting the base salary component of our overall compensation program but emphasizing performance bonuses and offering the opportunity to achieve large equity rewards, we are able to attract and retain executive officers from a specifically targeted group. These are individuals with proven leadership skills who are mature in their careers and thus have financial resources that allow them to accept the financial risks involved in such a compensation arrangement.

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Elements of Compensation

The elements of compensation of our officers and our employees generally consist of:

Base Salary

In determining base salary for each executive officer, the compensation committee considers the executive s experience and position within the Managing General Partner. The compensation committee also utilizes industry compensation surveys provided by independent advisors. In addition, the compensation committee, in setting salaries for executive officers, takes into account the recommendations of the Chief Executive Officer (CEO), or, in the case of the CEO, the recommendation of the chairman of the compensation committee.

Annual Bonuses

At the beginning of each fiscal year, our board approves annual corporate objectives, including a budget, and these, along with personal performance objectives, are reviewed at the end of the year for the purpose of determining annual bonuses. Annual assessments of executive officers include an evaluation of other performance measures, including the promotion of teamwork, leadership, and the development of individuals responsible to the applicable officer.

Determinations of the CEO s annual bonus are significantly influenced by the extent of the achievement of corporate objectives, and determinations of the annual bonuses of the other executive officers are significantly influenced by the extent of the achievement of corporate objectives and the achievement of individual objectives.

Equity-Based Awards

A portion of executive officer compensation (as well as compensation of senior managers) is also directly aligned with growth in unit value. In reviewing equity-based awards to executive officers, including options, restricted units, phantom units and distribution rights, the compensation committee gives consideration to the number of such awards already held by each individual and to the number of units previously acquired in exchange for the Acquisition Equity Awards discussed below. Equity-based awards may be awarded to executive officers at the commencement of their employment, annually on meeting corporate and individual objectives, and from time to time by the compensation committee based on regular assessments of the compensation levels of comparable companies. An executive officer may earn an annual equity-based award on a basis similar to that described above under Annual Bonus, with similar weightings applied to the achievement of corporate objectives and individual objectives.

Deferred Compensation

The only deferred compensation element of our compensation program is our 401(k) plan.

Why We Choose to Pay Each Element

Salaries and Bonuses

We choose to pay salaries and bonuses to recognize an employee s role, responsibilities, skills, experience and performance. Until the initial public offering of the Partnership, the only compensation elements offered to management were salaries, bonuses and 401(k) deferred compensation. In recognition of our strategy to generate cash to make acquisitions and to pay debt, we initially set salaries in the lower range of competitiveness. Performance-based bonuses were emphasized. By the time of our initial public offering, the expansion of our business required that we recruit additional individuals to the management team and the compensation committee increased salaries to competitive levels. We continue to emphasize performance-based bonuses.

LTIP Awards

The LTIP was adopted at the time of the initial public offering of the Partnership in 2006. In adopting the LTIP, our board of directors recognized that it needed a source of equity to attract new members to the management team, as well as to provide an equity incentive to all other employees. We believe the LTIP promotes a long-term focus on results and aligns employee and unitholder interests.

The only awards made under the LTIP have been unit options or restricted units. Unit options represent the right to purchase the underlying units at a price equal to the market value of the units at the date of grant subject to the vesting of that right. In general, options awarded under our LTIP vest as to one-third of the units subject to the option on each of the first three anniversaries of the date of the award.

Restricted units so awarded may not be sold until vested and unvested restricted units will be forfeited at the time the holder terminates employment. In general, restricted units awarded under our LTIP vest as to one third of the award on each of the first three anniversaries of the date of the award. Restricted units participate in distributions on the same basis as other common units.

Deferred Compensation

At the time of its acquisition, Regency Gas Services LLC had established a 401(k) plan for its employees. That plan has been revised and continued but does not constitute a major element of our compensation structure. The current plan is provided to assist our employees in saving some amount of their cash compensation for retirement in a tax efficient manner.

Perquisites

Perquisites are not a significant factor in our compensation structure.

Determinations as to Amounts of Compensatory Elements

General

Annual compensation of our executive officers consists of a base salary component and a bonus component. Executive officers are also recipients of awards of equity, either initially through the Acquisition Equity Awards or, after our initial public offering, as participants in the LTIP. It is the intention of the compensation committee that the combination of equity ownership, base salary and bonus should be set at levels designed to attract and retain a strongly motivated leadership team but not so high as to create a negative perception in our unitholders and other stakeholders.

At a meeting in December 2005, the compensation committee considered a report and recommendation by management (the 2006 management recommendation) with respect to salaries, target bonuses and LTIP awards for outside directors, executive officers and employees of the Managing General Partner for the year 2006. The 2006 management recommendation was based on advice and information provided by BP regarding salaries and target bonuses for our executive officers and employees. The information provided by BP included salary and bonus scale, but not LTIP, information for officers and employees of (i) a large group of companies of approximately our size engaged in the energy business generally and (ii) a small group of companies of approximately our size engaged in the midstream natural gas business, including Atlas Pipeline, Copano Energy, Crosstex Energy, Inc., Energy Transfer Partners, L.P., Holly Corporation, Midwest Energy Partners LP, Martin Midstream and TEPPCO Partners. The 2006 management recommendation also included management s recommendations as to LTIP awards. While the committee took the 2006 management recommendation into consideration, its decisions were the results of the judgments of the committee members and frequently differed from the recommendation.

Salary

At its December 2005 meeting, the compensation committee considered the 2006 management recommendation with respect to salaries for our then executive officers for the year 2006. At that meeting, the

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compensation committee established a salary pool for 2006 and established salaries for the officers and key employees. While the compensation committee did not regard it as a benchmark, it took note of the 50 percentile or median of the salary scale of the large group of energy companies described above. The compensation committee raised the salaries of our CEO, CFO and named executive officers to the amounts set forth in the footnotes to the summary compensation table effective at the time of completion of our initial public offering (February 3, 2006). The compensation committee took these actions to bring these salaries more into alignment with the energy industry. Consistent with the committee s views regarding preservation of cash, the increased salaries were, on average, approximately 19 percent lower than the recommendations of BP.

At its meeting on March 8, 2007, the compensation committee established a salary pool for 2007 and approved an increase of Mr. Suggs salary by $20,000 per year in connection with his promotion to Senior Vice President. All other named executive officers salaries remain unchanged.

Bonus

At the December 2005 meeting, the compensation committee, after considering the 2006 management recommendation, adopted target bonus levels for all the officers of the Managing General Partner under its 2006 bonus plan. The targets were based on achievement of our company s performance goals for fiscal 2006 as established by our budget for that year and measured by the key performance metrics described under Reward Objectives. For our CEO, CFO and NEOs these targets were: Mr. Hunt 100 percent of base salary ($400,000); Mr. Arata 75 percent of base salary ($187,500); Mr. Williams 100 percent of base salary ($300,000); Mr. Joor 75 percent of base salary ($161,250); and Mr. Suggs 75 percent of base salary ($135,000). These bonus targets, when combined with base salaries, represented target cash compensation levels that were on average approximately 1 percent more than those recommended by the independent consultant, reflecting the compensation committee s emphasis on rewarding performance.

At a meeting of the compensation committee held January 23, 2007, the officers of the Managing General Partner offered to forgo all their bonuses under the 2006 bonus plan in excess of small Christmas bonuses previously received. This offer was initiated by the executive officers voluntarily and was predicated on the failure of the Partnership to achieve its announced prediction of EBITDA for 2006 because of delayed in-service dates on three organic growth projects. Accordingly the summary compensation table includes no bonuses for the named executive officers other than Christmas bonuses.

At its meeting on March 8, 2007, the compensation committee established target bonuses for the executive officers that, in the cases of the CEO, CFO, and NEOs, were the same as those for 2006.

LTIP

At the time of our initial public offering, our Managing General Partner adopted our LTIP for employees (including executive officers), consultants and directors of the Managing General Partner who perform services for us. At that meeting, the compensation committee recommended, and the board approved, awards, effective at the time of our initial public offering (February 3, 2006), of unit options and restricted units (with unit distribution rights) under the LTIP to the outside directors, our then executive officers and virtually all our then employees.

The 2006 management recommendation regarding LTIP awards was based on the expectation that the number of common units subject to the LTIP, a number that was determined by HM Capital prior to our initial public offering, would fund awards over approximately five years. The awards for 2006 were, in the aggregate, greater than would be anticipated in future years, totaling about 30% of the aggregate number of units subject to the plan.

In making its recommendation, management divided the potential recipients into groups: (i) outside directors; (ii) Acquisition Equity Award holders (who, at the time, included all our executive officers); and (iii) four tiers of employees based on levels of responsibility. Of the 2,865,584 common units subject to the LTIP, the compensation committee recommended, and the board of directors granted, unit option awards with respect to 599,300 common units and restricted unit awards with respect to 262,500 common units or an aggregate of 861,800 potential common units. The outside directors were awarded restricted units and unit options representing 4 percent of the units awarded and 5 percent of the value of all awards (valuing restricted units at $20 per unit, being the initial offering price, and options at $1.15 per unit, the value determined pursuant to FAS 123(R)). The holders of Acquisition Equity Awards received awards representing 39 percent of the units awarded and 16 percent of the value of the awards. These holders, with the exception of one key employee, all received unit options. All other employees (approximately 150 individuals) received awards representing 57 percent of the units awarded and 79 percent of the value of the awards.

For the balance of 2006, awards were made under the LTIP primarily (i) to attract and retain employees and (ii) to employees of TexStar Field Services, L.P. at the time of its acquisition (August 15, 2006). A very few retention awards were made to non-officer employees.

On March 8, 2007, pursuant to recommendations by management and after consultation with HG, the compensation committee made additional awards under the LTIP to 33 employees. In accordance with the views of the compensation committee that the units acquired by the CEO, CFO and NEOs in exchange for Acquisition Equity Awards provide sufficient performance incentive for the present, none of them was granted any additional award under the LTIP except Mr. Suggs who, in conjunction with his promotion to Senior Vice President, was awarded 4,000 restricted units.

401(k) Plan

The only deferred compensation plan offered by the Managing General Partner is a 401(k) Plan. Under that plan, participants may contribute up to 75 percent of their base salaries (subject to a maximum of $15,000 in 2006) and the Managing General Partner will contribute a matching amount equal to 50 percent of the employee s contribution (subject to a maximum of three percent). All amounts contributed by the Managing General Partner to the accounts of the named executive officers are included in the summary compensation table.

Employment Agreements

We maintain employment agreements with our CEO and Chief Operating Officer to ensure they will perform their roles for an extended period of time. These agreements are described in more detail under Employment Agreements. These agreements provide for severance compensation to be paid if the employment of the executives is terminated under certain conditions, such as termination by him for good reason or by us for cause, each as defined in the agreements. If we terminate the employment of an executive officer without cause as defined in the applicable agreement, we are obligated to continue to pay him certain amounts as described in greater detail in Potential Payments Upon Termination. We believe these payments are appropriate because the terminated executive is bound by confidentiality, nonsolicitation and non-compete provisions covering two years after termination and because we and the executive have a mutually agreed to severance package that is in place prior to any termination event. This provides us with more flexibility to make a change in senior management if such a change is in the best interests of the Partnership and our unitholders.

Summary Compensation

The following table summarizes, with respect to our named executive officers, information relating to the compensation earned for services rendered in all capacities during fiscal year 2006.

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Summary Compensation for the Year Ended December 31, 2006

Name and Principal Position	Year (1)	Salary ($)(2)	Bonus ($)(3)	Stock Awards ($)	Option Awards ($)(4)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)(5)	Total ($)
James W. Hunt President, Chief Executive Officer and Chairman of the Board	2006	386,667	10,000		35,046			7,600	439,313
Stephen L. Arata Executive Vice President and Chief Financial Officer	2006	245,833	6,250		12,266			6,250	270,599
Michael L. Williams Executive Vice President and Chief Operating Officer	2006	292,500	7,500		14,018			19,901	333,919
William E. Joor III Executive Vice President and Chief Legal and Administrative Officer and Secretary	2006	213,750	5,375		12,266			17,051	248,442
Alvin Suggs Vice President and General Counsel	2006	180,000	4,500		5,257			4,500	194,257
Durell J. Johnson Vice President Operations, Regency Gas Services LP	2006	176,250	4,500		5,257			17,782	203,789

(1) We became subject to the reporting requirements under Section 13(a) of the Exchange Act on February 3, 2006, and included executive compensation for 2005 in the registration statement under the Securities Act relating to our initial public offering.

(2) Salary levels for each of the named executive officers for 2006 were as follows: Mr. Hunt $400,000; Mr. Arata $250,000; Mr. Williams $300,000; Mr. Joor $215,000; and Mr. Suggs $180,000.

(3)

Represents Christmas bonus only. The officers voluntarily waived the remainders of their bonuses for 2006. Please read Determinations as to Amounts of Compensatory Elements Bonuses.

(4) The amounts included in the Option Awards column include the dollar amount of compensation expense we recognized for the fiscal year ended December 31, 2006 in accordance with FAS 123(R). Assumptions used in the calculation of these amounts are included in Note 16 to our audited financial statements for the fiscal year ended December 31, 2006. All the unit options were granted on February 3, 2006 at an exercise price equal to the initial public offering price of $20 per unit and were valued at the FAS 123(R) value of $1.15 per unit subject to the option.

(5) Includes perquisites and other personal benefits of $12,626 for Mr. Williams, $11,713 for Mr. Joor and $12,495 for Mr. Johnson. These amounts represent reimbursements of travel expenses from their homes in other cities to and from the Dallas office. All other amounts represent employer matching contributions to 401(k) accounts.

Grants of Plan-Based Awards

The Partnership s Long Term Incentive Plan, or LTIP, was adopted on its behalf by action of the board of directors of our Managing General Partner on December 12, 2005. While the LTIP was originally administered by the board, the board delegated its authority to administer the LTIP to the compensation committee in November 2006.

At the time of our initial public offering (which was consummated on February 3, 2006), our board, in conjunction with awards of unit options or restricted units to virtually all our employees, granted unit options to our CEO, CFO and the other NEOs at the initial public offering price of $20.00 per common unit. No

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further awards were made to any of those officers until March 8, 2007, at which time the compensation committee made only the award of 4,000 restricted units to Mr. Suggs, as set forth in the following table:

The following table provides information concerning each grant of an award made to our named executive officers in the last completed fiscal year under any plan, including awards that have been transferred.

Grants of Plan-Based Awards for the Year Ended December 31, 2006

			Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Stock Awards: Number of Shares of Stock or Units	All Other Option Awards: Number of Securities Under-lying Options	Exercise or Base Price of Option Awards	Grant Date Fair Value of Stock and Option Awards
Name(1)	**Grant Date**	**Approval Date**	**Thresh-old ($)**	**Target ($)**	**Maxi-mum ($)**	**Thresh-old (#)**	**Target (#)**	**Maxi-mum (#)**	**(#)**	**(#)**	**($/Sh)**	**($)(2)**
James W. Hunt	2/3/06	12/12/05								100,000	$ 20.00	115,000
Stephen L. Arata	2/3/06	12/12/05								35,000	$ 20.00	40,250
Michael L Williams	2/3/06	12/12/05								40,000	$ 20.00	46,000
William E. Joor III	2/3/06	12/12/05								35,000	$ 20.00	40,250
Alvin Suggs	2/3/06	12/12/05								15,000	$ 20.00	17,250
	3/8/07	12/12/05							4,000(3)		$ 27.70	
Durell J. Johnson	2/3/06	12/12/05								15,000	$ 20.00	17,250

(1) None of the CEO, CFO and NEOs has exercised any option awarded under the LTIP and, accordingly, their holdings at December 31, 2006 were as set forth in the table. Since that date, the only LTIP award made to any of them is the award of 4,000 restricted units on March 8, 2007 to Mr. Suggs (none of which has vested).

(2) These amounts are based on the FAS 123(R) value of $1.15 per unit subject to the option. No value was allocated to the restricted unit award to Mr. Suggs because none of the restricted units has vested.

(3) The closing price per common unit on The Nasdaq Global Select Market on March 8, 2007 was $27.70.

Narrative Disclosure to Summary Compensation and Grants of Plan-Based Awards Table

LTIP Policy

The awards made on February 3, 2006 as set forth in the table were the only awards made under the LTIP to any of the officers listed in the table that were outstanding at the end of our fiscal year 2006.

As indicated above, awards under our LTIP prior to 2007 were made only (i) at the time of our initial public offering, (ii) at the time of our acquisition of TexStar Field Services, LP, (iii) from time to time as necessary to attract and retain employees and (iv) to retain a few non-officer employees.

Commencing in 2007, we anticipate making awards on a more regular basis. At the start of the year, our board adopted a policy with respect to the granting of such awards. Pertinent portions of that policy are summarized below.

Grants to Existing Employees

Grants of restricted units and options to existing employees may be made only upon resolution, duly adopted by either the board or its compensation committee.

Grants to New Employees

Grants of restricted units or options to new employees may be made upon approval of the board or its compensation committee, or, within the limits provided, by action of the CEO. No commitment may be made by any officer or employee of the Managing General Partner with respect to the award of restricted units or options to a prospective new employee until the actions described above have been effected.

Option Exercise Prices

Options granted under the LTIP must be (i) dated (being the date of grant) as of the later of the date of grant of the option by the board, the compensation committee or the CEO and the date of fulfillment of any condition or conditions imposed in connection with the entitlement to such grant and (ii) priced as of the close of business on the date of grant. In the case of options granted by the CEO, the date of grant is the later of the date of the letter of the CEO referenced above and the date of fulfillment of any condition imposed thereby.

Documentation

Promptly after the award of any restricted unit or option as provided above, the CFO shall cause that restricted unit or option to be reflected in an award executed on behalf of the Partnership and provided to the recipient. A copy of such award, as well as a cumulative tally of all such awards, must be maintained at the direction of the CFO.

Acceleration of Vesting

The LTIP provides that, on termination of employment or another relationship between the Partnership and the holder of restricted units or an option (other than as a result of death), the holder s rights to all unvested units are terminated. If that provision is altered with respect to any holder by the board of directors, the compensation committee or the CEO, that action shall be reflected in the minutes of actions by the board or the compensation committee or in a letter signed by the CEO.

The compensation committee has not delegated any authority regarding the granting of awards except that (i), during 2006, it authorized the CEO to make awards of up to 50,000 restricted units and options to purchase up to 150,000 common units in connection with the employment of employees (ii), in March 2007, it authorized the CEO to make awards of up to 200,000 restricted units in connection with the employment of employees and to retain existing employees (none of which has yet been granted) and (iii) it authorized the CEO, under appropriate circumstances, to accelerate the vesting of previously granted awards in connection with the termination of employment of an employee.

Option Exercises and Vesting

None of the CEO, CFO or other NEOs has exercised any option awarded under the LTIP and the only restricted unit award made under the LTIP to any of them has not vested.

Employment Agreements

At the time of their employment by Regency Gas Services LLC on December 1, 2004, both James W. Hunt, President and Chief Executive Officer, and Michael L. Williams, Executive Vice President and Chief Operating Officer, entered into employment agreements with Regency Gas Services LLC. Each agreement provides for a term of three years, a minimum base salary of $240,000 and $210,000 for Mr. Hunt and Mr. Williams, respectively, participation by the employee in the benefit plans adopted by the employer, and the Acquisition Equity Awards described above.

In each case, the agreement provides that the employee s employment will terminate on the employee s death and may terminate on his disability, In addition, the employer may terminate the agreement at any time for cause (as defined) and, at any time after the expiration of the first six months, without cause. The employee may terminate the agreement at any time for good reason (as defined) and, at any time after the first six months, without good reason. The employee may also terminate his employment without good reason during the 30 days following a change of control (as defined). In each case, if the employee s employment is terminated by death or disability or by the employer without cause or by the employee for good reason, the employee or his estate will be entitled to the severance amount described below under Potential Payments Upon Termination. If employee s employment is terminated for any other reason, the employee is entitled only to his base salary through the date of termination and any vested amounts under employee benefit plans. The severance amount is, generally, twice the sum of employee s annual base salary and the bonus received or due for the calendar year preceding the year in which the date of termination occurs. Each employee has agreed, for a period of at least two years following the date of termination of his employment, not to compete with the employer and not to solicit the employer s customers, suppliers, employees or other of the employer s business relations.

At the time of his employment by Regency Gas Services LLC, Mr. Joor entered into a severance agreement with the employer. The severance agreement generally provides that, if at any time during the three years commencing on the date of his employment, January 1, 2005, Mr. Joor s employment is terminated because of death or disability or by the employer without cause (as defined) or by Mr. Joor for good reason (as defined), the employee or his estate will be entitled to a severance payment of $600,000 if the termination occurs during the first year, declining by $200,000 per year thereafter.

Potential Payments Upon Termination

We have entered into the two employment agreements and the severance agreement described above that will require us to provide compensation and/or benefits to our named executive officers in the event of a termination of employment under certain circumstances. The compensation and benefits described below assume that the employment of each of the executive officers named below was terminated by us for cause or by the employee for good reason effective as of December 31, 2006, and thus includes amounts earned through that date. The description set forth below provides estimates of the compensation and benefits that would be provided to the executives upon their termination of employment; however, in the event of an executive s separation from the Company, any actual amounts will be determined based on the facts and circumstances in existence at that time.

Name	Termination Benefit ($)
James W. Hunt	1,600,000(1)
Michael L. Williams	1,200,000(1)
William E. Joor III	200,000

(1) Represents two times the sum of base salary and 100% of target bonus.

Certain Relationships and Related Party Transactions

On March 22, 2007, our board adopted a policy with respect to related party transactions. That policy works in conjunction with the provisions of our partnership agreement that govern such transactions.

Under our partnership agreement, a transaction involving conflicts of interest is permissible only if (1) it is approved by the conflicts committee of our board, (2) it is approved by our limited partners (unitholders), (3) it is on terms no less favorable to the Partnership than those generally being provided to or available from unrelated third parties or (4) it is fair and reasonable to the Partnership, taking into account the totality of the relationships between the parties involved (including other transactions that may be particularly favorable or advantageous to the Partnership).

Under the related party transaction policy, a transaction involving a conflict of interest believed to be encompassed by clause (3) or (4) above may be approved by our conflicts committee or a disinterested majority of our board. Such a transaction may also be approved by our CEO if it is in the ordinary and normal course of the business of the Partnership or any of its subsidiaries and our CEO determines that it meets the criteria set forth in clause (3) or (4). Related party transactions involving less than $120,000, subject to approval in accordance with our levels of authority policy, do not require special approval.

Our compensation committee monitors and reviews issues involving potential conflicts of interest and related party transactions. The only related party transactions involving the Partnership or any of its

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subsidiaries since our initial public offering were those that were disclosed in connection with that offering and those relating to our acquisition of TexStar Field Services, L.P. from an affiliate of HM Capital which were approved by the conflicts committee of our board. Of the latter, the only continuing transactions are those under gas purchase contracts executed in connection with the acquisition involving our purchase of natural gas for processing from an affiliate of HM Capital.

Our company is currently in discussion with an affiliate of HM Capital with respect to a sublease of office space in San Antonio, Texas. The annual rental of that space would be at the same rental rate as paid by the lessee and would be approximately $360,000. We will not enter into this transaction unless it is approved in accordance with our related party transaction policy.

Directors Compensation

The directors of the Managing General Partner who are not employees of the Managing General Partner or affiliated with the Managing General Partner s controlling security holder received in 2006 an annual retainer of $25,000, a flat fee of $1,000 for each meeting of the board and $500 for each committee attended in person, a flat fee of $500 for each such meeting attended by telephone and fees at specified rates for consulting services. These amounts are determined on an annual basis by our board. In addition, those directors are eligible to participate in equity-based compensation plans of the Managing General Partner. Determinations as to any such participation are made by the non-participating directors.

The following table presents the cash, equity awards and other compensation earned, paid or awarded to each of our directors during the year ended December 31, 2006.

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)(1)	Option Awards ($)(2)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)	Total ($)
Joe Colonnetta	31,000						$ 31,000
Jason H. Downie	33,500						33,500
A. Dean Fuller	52,500	30,556	5,750				88,806
Jack D. Furst	28,500						28,500
J. Edward Herring	31,000						31,000
Robert D. Kincaid(3)	38,750	30,556	5,750				75,056
Gary W. Luce(3)	43,750	30,556	5,750				80,056
Robert W. Shower	47,500	30,556	5,750				83,806
J. Otis Winters	50,000	30,556	5,750				86,806

(1)

Each amount shown represents the vested portion (1,666 common units) of an award of 5,000 restricted units awarded to each of the outside directors at the time of our initial public offering valued at the initial public offering price of $20 per unit. The amounts included in the Stock Awards column include the dollar amount of compensation expense we recognized for eleven months of the fiscal year ended December 31, 2006 in accordance with the Statement of Financial Accounting Standards No. 123(R). Assumptions used in the calculation of these amounts are included in Note 16 to our audited financial statements for the fiscal year ended December 31, 2006 included in our annual report on Form 10-K. The grant date fair value of each director s award as computed in accordance with FAS 123(R) is $20 per unit.

(2) Each amount shown represent an option granted to each of the outside directors at the time of our initial public offering to purchase 5,000 common units at the initial public offering price of $20 per unit and valued at the FAS 123(R) value of $1.15 per common units subject to the option. The amounts included in the Option Awards column include the dollar amount of compensation expense we recognized for the fiscal year ended December 31, 2006 in accordance with FAS 123(R). Assumptions used in the calculation of these amounts are included in Note 16 to our audited financial statements for the fiscal year ended

December 31, 2006 included in our annual report on Form 10-K. The grant date fair value of each director s award as computed in accordance with FAS 123(R) is $1.15 per unit.

(3) The amounts shown for Messrs. Kincaid and Luce exclude the Acquisition Equity Awards received by them as described under Background.

Messrs. Colonnetta, Downie, Furst, and Herring are officers of HM Capital, a related party. All fees paid to these directors are remitted directly to HM Capital.

Compensation Committee Report

We have reviewed and discussed with management certain Compensation Discussion and Analysis provisions to be included in the Partnership s Annual Report on Form 10-K for the year ended December 31, 2006 to be filed pursuant to Section 13(a) of the Securities Exchange Act of 1934 (the Annual Report). Based on those reviews and discussions, we recommend to the board of directors of Regency GP LLC, the general partner of Regency GP LP, the general partner of the Partnership, that the Compensation Discussion and Analysis be included in the Annual Report.

Compensation Committee

Jason H. Downie, Chairman
Joe Colonnetta
J. Otis Winters

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

The following table sets forth, as of March 1, 2007, the beneficial ownership of our units by:

each person who then owned beneficially 5 percent or more of our units;

each member of the board of directors of Regency GP LLC;

each named executive officer of Regency GP LLC; and

all directors and executive officers of Regency GP LLC, as a group.

Ownership information regarding the common units and subordinated units set forth in the following table is derived from:

the holdings thereof by HMTF Regency, L.P. and the resulting economic interest therein of the persons named in the table pursuant to their ownership of Class A Units of HMTF Regency, L.P.; or

the exchange of Class B Units and Class D Units of net profits interests in HMTF Regency, L.P. held by persons named in the table prior to the IPO for common and subordinated units.

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

Name of Beneficial Owner	Common Units	Percentage of Outstanding Common Units(5)	Subordinated Units	Percentage of Outstanding Subordinated Units(5)	Percentage of Total Units
HM5/GP LLC(1)	8,148,672	29.5%	16,699,462	87.4%	53.1%
James W. Hunt(2)(3)	107,326	0.4	840,678	4.4	2.0
Michael L. Williams(2)(3)	112,758	0.4	480,387	2.5	1.2
Stephen L. Arata(2)(3)	61,378	0.2	240,194	1.3	0.6
William E. Joor III(2)(3)	86,235	0.3	360,290	1.9	0.9
Alvin Suggs(2)(3)	19,914	0.1	72,058	0.4	0.2
Joe Colonnetta(1)(2)	25,000	0.1		(4)	0.1
Jason H. Downie(1)(2)	11,000	(4)		(4)	(4)
A. Dean Fuller(2)(3)	14,166	(4)		(4)	(4)
Jack D. Furst(1)(2)	12,500	(4)		(4)	(4)
J. Edward Herring(1)(2)	10,000	(4)		(4)	(4)
Robert D. Kincaid(2)(3)	14,381	(4)	37,278	0.2	0.1
Gary W. Luce(2)(3)	14,381	(4)	37,278	0.2	0.1
J. Otis Winters(2)(3)	11,666	(4)		(4)	(4)
All directors and executive Officers as a group (20 persons)	8,797,543	31.8	18,911,741	99.0	59.3

(1) According to Schedule 13D/ A (Amendment No. 4) dated March 30, 2007 (the Schedule 13D) filed jointly by Regency Acquisition LP, a Delaware limited partnership (Acquisition); Regency Holdings LLC, a Delaware limited liability company and the general partner of Acquisition (Holdings); HMTF Regency, L.P., a Delaware limited partnership which is the sole member of Holdings and owns all of the limited partnership interest in Acquisition (HMTF Regency); HMTF Regency, L.L.C., a Texas limited liability company and the general partner of HMTF Regency (HMTF GP); Hicks, Muse, Tate & Furst Equity Fund V, L.P., a Delaware limited partnership and the sole member of HMTF GP (Fund V); and HM5/ GP LLC, a Texas limited liability company, the general partner of Fund V (HM5); and, together with Acquisition, Holdings, HMTF Regency, HMTF GP, and Fund V and the 13D Parties), (i) Acquisition is the record owner of 3,456,255 common units and 16,699,462 subordinated units; Fund V is the record owner of 4,592,464 common units; HMTF GP, L.L.C. (HMTF Gas GP), of which Fund V is the sole member, is the record owner of 3 common units; and two limited partnerships (the Coinvest LPs) of which HM5 is the general partner are the record owner of an aggregate of 99,950 common units; (ii) as a result of the relationship of HM5 to Fund V, Fund V to HMTF GP, HMTF GP to HMTF Regency, HMTF Regency to Holdings, and Holdings to Acquisition, each 13D Party may be deemed to have shared power to vote, or direct the disposition of, and to dispose, or direct the disposition of, the common units and subordinated units held of record by Acquisition. (iii) as a result of the relationship of Fund V to HMTF Gas GP, Fund V may be deemed the beneficial owner of the common units held by HMTF Gas GP; (iv) as a result of the relationship of HM5 to Fund V, HM5 may be deemed the beneficial owner of all of the common units held by Fund V; and (v) as a result of the relationship of HM5 to the Coinvest LPs, HM5 may be deemed the beneficial owner of the common units held by the Coinvest LPs.

(2) The common units amounts include unit options which are currently exercisable in the following amounts of common units: Mr. Hunt 33,333; Mr. Williams 13,333; Mr. Arata 11,666; Mr. Joor 11,666; Mr. Suggs 5,000; Mr. Fuller 1,666; Mr. Kincaid 1,666; Mr. Luce 1,666 and Mr. Winters 1,666.

(3) Each of these executive officers disclaims beneficial ownership of any common and subordinated units held by HMTF Regency, L.P. resulting from his ownership of Class A Units of HMTF Regency, L.P. by each such person as he does not have voting or dispositive control of these units. These units include the following: Mr. Hunt 18,817 common and 90,920 subordinated; Mr. Williams 4,897 common and 23,659 subordinated; Mr. Arata 4.897 common and 23,659 subordinated; Mr. Joor 4,897 common

and 23,659 subordinated; and Mr. Suggs 1,959 common and 9,464 subordinated. Each of these executive officers will be treated as regards his ownership of Class A Units, in the same manner as any other HM Capital Investor. The address of each of these individuals is 1700 Pacific, Suite 2900, Dallas, Texas 75201.

(4) Ownership percentages are less than 0.1 percent.

(5) The number of common units and subordinated units outstanding are 27,844,291 and 19,103,896, respectively.

Securities Authorized for Issuance under Equity Compensation Plans

The following table provides information concerning common units that may be issued under the Regency GP LLC Long-Term Incentive Plan (LTIP). In connection with our IPO, our Managing General Partner adopted the LTIP for employees, directors and consultants of our general partner. The LTIP consists of restricted units, phantom units and unit options. It currently permits the grant of awards covering an aggregate of 2,865,584 units. The LTIP is administered by the compensation committee of the board of directors of our Managing General Partner.

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

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted- Average Exercise Price of Outstanding, Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (c)
Equity compensation plans approved by security holders			
Equity compensation plans not approved by security holders	909,600	$ 21.06	1,405,184
Total	909,600	$ 21.06	1,405,184

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

Review, Approval and Ratification of Transactions with Related Persons

As of December 31, 2006, HM Capital Investors own 9,127,085 common units and 19,103,896 subordinated units representing a 60.2 percent limited partner interest in us.

Distributions and Payments to Our General Partner and its Affiliates

Under our partnership agreement, our General Partner and its affiliates will be entitled to reimbursement for all expenses it incurs on our behalf, including salaries and employee benefit costs for its employees who provide services to us, and all other necessary or appropriate expenses allocable to us or reasonably incurred by our general partner and its affiliates in connection with operating our business. The partnership agreement provides that our General Partner will determine the expenses that are allocable to us in good faith.

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

Omnibus Agreement

Upon the closing of our initial public offering, we entered into an omnibus agreement with Regency Acquisition LP pursuant to which Regency Acquisition LP agreed to indemnify us against certain environmental and related liabilities arising out of or associated with the operation of the assets before the consummation of our initial public offering. This indemnification obligation will terminate on February 3, 2009. There is an aggregate cap of $8,600,000 on the amount of indemnity coverage for environmental and related liabilities. In addition, we are not entitled to indemnification until the aggregate amount of all claims under the omnibus agreement exceed $250,000. Liabilities resulting from a change of law after our initial public offering are excluded from the environmental indemnity by Regency Acquisition LP for the unknown environmental liabilities. To date, no claims have been made against the omnibus agreement.

Regency Acquisition LP has also indemnified us for liabilities related to:

- certain defects in the easement rights or fee ownership interests in and to the lands on which any assets contributed to us are located and failure to obtain certain consents and permits necessary to conduct our business that arise within two years after the closing of the initial public offering; and

- certain income tax liabilities attributable to the operation for the assets contributed to us prior to the time they were contributed.

Amendments

The omnibus agreement may not be amended without the prior approval of the conflicts committee if the proposed amendment will, in the reasonable discretion of our General Partner, adversely affect holders of our common units.

Competition

Regency Acquisition LP is not restricted under the omnibus agreement from competing with us. Regency Acquisition LP may acquire, construct or dispose of 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.

Related Party Transactions

Concurrently with the closing of our initial public offering, we paid $9,000,000 to an affiliate of HM Capital Partners to terminate a management services contract with a remaining tenor of 9 years.

BlackBrush Oil & Gas, LP (BBOG), an affiliate of the Partnership, is a shipper on the Partnership s gas gathering and processing system. During the years ended December 31, 2006 and 2005, we generated revenues of $2,160,000 and

$833,000 on transportation and compression of natural gas for BBOG. We also incurred related party expenses of $1,630,000 and $523,000 for the years ended December 31, 2006 and 2005.

TexStar entered into a management services contract with HMTF Gas Partners on July 30, 2004. We paid management fees in the amount of $361,000 to HM Capital during the year ended December 31, 2006. In connection with the acquisition of TexStar, we paid $3,542,000 to terminate TexStar s management services contract.

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In connection with the TexStar acquisition, BBOG entered into five gas gathering agreements providing for the long term dedication to TexStar of the production from its leases. Under those agreements, we gather and process natural gas and receive payment for these services.

In February of 2005, TexStar issued a promissory note to HM Capital Partners in the amount of $600,000 bearing interest at a fixed rate of 8.5 percent per annum. Concurrent with the Partnership s acquisition of TexStar in August 2006, the promissory note was repaid in full.

The employees that operate our assets and provide staff or support services are employees of Regency GP LLC, our Managing General Partner. Pursuant to our partnership agreement, our Managing General Partner receives a monthly reimbursement for all direct and indirect expenses that it incurs on our behalf. We recorded reimbursements of $16,789,000 during the year ended December 31, 2006 as operating and maintenance expenses or general and administrative expenses.

We made cash distributions of $20,139,000 during the year ended December 31, 2006 to HM Capital Partners and affiliates as a result of their ownership of a portion of the Partnerships common and subordinated units, and their ownership of the general partner interest.

TexStar paid a transaction fee in the amount of $1,200,000 to an affiliate of HM Capital upon completing its acquisition of the Como Assets. This amount was capitalized as a part of the purchase price.

On August 15, 2006, we completed the acquisition of all the outstanding equity of TexStar. The purchase price for the TexStar Acquisition was paid by (1) the issuance of 5,173,189 Class B common units of the Partnership to HMTF Gas Partners, (2) the payment of $62,074,000 in cash and (3) the assumption of $167,652,000 of TexStar s outstanding bank debt.

Item 14. ***Principal Accounting Fees and Services.***

The following set forth fees billed by Deloitte & Touche LLP for the audit of our annual financial statements and other services rendered for the fiscal years ended December 31, 2006 and 2005:

	December 31,	
	2006	**2005**
Audit fees(1)(2)	$ 1,419,000	$ 1,180,000
Audit related fees(3)	18,500	60,000
Tax fees(4)	45,000	53,000
All other fees(5)		
Total	$ 1,428,500	$ 1,293,000

(1) Includes fees for audits of annual financial statements of our companies, reviews of the related quarterly financial statements, and services that are normally provided by the independent accountants in connection with statutory and regulatory filings or engagements, including reviews of documents filed with the SEC. The year ended December 31, 2005 fees include an audit of our financial statements at June 30, 2005 in connection with

our initial public offering.

(2) The 2006 amounts includes fees for the June 30, 2006, December 31, 2005 and December 31, 2004 audits and quarterly reviews from January 1, 2005 to June 30, 2006 of TexStar.

(3) Includes fees related to consultations concerning financial accounting and reporting standards and services related to the implementation of our internal controls over financial reporting.

(4) Includes fees related to professional services for tax compliance, tax advice, and tax planning. These tax services were incurred on behalf of HMTF Regency, L.P. for the years ended December 31, 2006 and 2005.

(5) Consists of fees for services other than services reported above.

Pursuant to the charter of the Audit Committee, the Audit Committee is responsible for the oversight of our accounting, reporting and financial practices. The Audit Committee has the responsibility to select,

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appoint, engage, oversee, retain, evaluate and terminate our external auditors; pre-approve all audit and non-audit services to be provided, consistent with all applicable laws, to us by our external auditors; and to establish the fees and other compensation to be paid to our external auditors. The Audit Committee also oversees and directs our internal auditing program and reviews our internal controls.

The Audit Committee has adopted a policy for the pre-approval of audit and permitted non-audit services provided by our principal independent accountants. The policy requires that all services provided by Deloitte & Touche LLP, including audit services, audit-related services, tax services and other services, must be pre-approved by the Audit Committee.

The Audit Committee reviews the external auditors proposed scope and approach as well as the performance of the external auditors. It also has direct responsibility for and sole authority to resolve any disagreements between our management and our external auditors regarding financial reporting, regularly reviews with the external auditors any problems or difficulties the auditors encountered in the course of their audit work, and, at least annually, uses its reasonable efforts to obtain and review a report from the external auditors addressing the following (among other items):

- the auditors internal quality-control procedures;
- any material issues raised by the most recent internal quality-control review, or peer review, of the external auditors;
- the independence of the external auditors;
- the aggregate fees billed by our external auditors for each of the previous two fiscal years; and
- the rotation of the lead partner.

Part IV

Item 15. *Exhibits and Financial Statement Schedules.*

(a)1. *Financial Statements*

See Index to Financial Statements set forth on page F-1

2. *Financial Statement Schedules*

Other schedules are omitted because they are not required or applicable, or the required information is included in the Consolidated Financial Statements or related notes.

3. *Exhibits*

See Index to Exhibits .

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Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

REGENCY GP LLC, its general partners

By: REGENCY ENERGY PARTNERS LP

By: REGENCY GP LP, its general partner

By: /s/ James W. Hunt

James W. Hunt
Chief Executive Officer and officer duly
authorized to sign on behalf of the registrant

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons in the capacities and on the dates indicated:

Signature	Title	Date
/s/ James W. Hunt	Chairman, President, and Chief Executive Officer (Principal Executive Officer)	March 30, 2007
James W. Hunt		
/s/ Stephen L. Arata	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 30, 2007
Stephen L. Arata		
/s/ Lawrence B. Connors	Vice President, Finance and Accounting (Principal Accounting Officer)	March 30, 2007
Lawrence B. Connors		
/s/ Joe Colonnetta	Director	March 30, 2007
Joe Colonnetta		
/s/ Jason H. Downie	Director	March 30, 2007
Jason H. Downie		
/s/ A. Dean Fuller	Director	March 30, 2007

A. Dean Fuller		
	Director	March 30, 2007
Jack D. Furst		
/s/ J. Edward Herring	Director	March 30, 2007
J. Edward Herring		
/s/ Robert D. Kincaid	Director	March 30, 2007
Robert D. Kincaid		

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Signature	Title	Date
/s/ Gary W. Luce	Director	March 30, 2007
Gary W. Luce		
/s/ J. Otis Winters	Director	March 30, 2007
J. Otis Winters		

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Index To Exhibits

Exhibit Number	Description
2.1**	Contribution Agreement by and among Regency Energy Partners LP, Regency Gas Services LP, as Buyer and HMTF Gas Partners II, L.P., as Seller dated July 12, 2006.
3.1*	Certificate of Limited Partnership of Regency Energy Partners LP
3.2*	Form of Amended and Restated Limited Partnership Agreement of Regency Energy Partners LP (included as Appendix A to the Prospectus and including specimen unit certificate for the common units)
3.2.1**	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Regency Energy Partners LP
3.2.2***	Amendment No. 2 to Amended and Restated Agreement of Limited Partnership of Regency Energy Partners LP
3.3*	Certificate of Formation of Regency GP LLC
3.4*	Form of Amended and Restated Limited Liability Company Agreement of Regency GP LLC
3.5*	Certificate of Limited Partnership of Regency GP LP
3.6*	Form of Amended and Restated Limited Partnership Agreement of Regency GP LP
4.1*	Form of Common Unit Certificate
4.2	Indenture for 83/8% Senior Notes due 2013, together with the global notes
10.1*	Amended and Restated Credit Agreement of Regency Gas Services LLC
10.2*	Amended and Restated Second Lien Credit Agreement of Regency Gas Services LLC
10.3*	Second Amended and Restated Credit Agreement of Regency Gas Services LLC
10.4*	Regency GP LLC Long-Term Incentive Plan
10.5*	Form of Grant Agreement for the Regency GP LLC Long-Term Incentive Plan Unit Option Grant
10.6*	Form of Grant Agreement for the Regency GP LLC Long-Term Incentive Plan Restricted Unit Grant
10.7*	Form of Grant Agreement for the Regency GP LLC Long-Term Incentive Plan Phantom Unit Grant (With DERS)
10.8*	Form of Grant Agreement for the Regency GP LLC Long-Term Incentive Plan Phantom Unit Grant (Without DERS)
10.9*	Form of Contribution, Conveyance and Assumption Agreement
10.10*	Executive Employment Agreement dated December 1, 2004 between the Registrant and James W. Hunt
10.11*	Employment Agreement dated December 1, 2004 between the Registrant and Michael L. Williams
10.12*	Severance Agreement dated January 1, 2005 between the Registrant and William E. Joor, III
10.13*	Purchase Agreement by and among Regency Acquisition LLC, Regency Services, LLC, Regency Gas Services LLC, the Members of Regency Services, LLC and the Partners of CB Offshore Equity Fund V Holdings, L.P. dated October 21, 2004
10.14*	Purchase and Sale Agreement between Duke Energy Field Services, LP and Regency Gas Services Waha, LP Dated January 29, 2004
10.15*	Pipeline Construction Contract between Regency Gas Services LLC and H.C. Price dated May 2, 2005 (relating to construction of 30 natural gas pipeline with facilities in Louisiana)
10.16*	Pipeline Construction Contract between Regency Intrastate Gas LLC and H.C. Price Co. dated May 2nd, 2005 (relating to the construction of 24 natural gas pipeline with facilities in

	Louisiana)
10.17*	Ground Lease Agreement (Lakin Plant)
10.18*	Ground Lease Agreement (Mocane Plant)
10.19*	Lisbon Lease Agreement
10.20*	Firm Transportation Agreement dated June 8, 2005 between Regency Intrastate Gas LLC and Anadarko Energy Services Company

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Exhibit Number	Description
10.21*	Form of Third Amended and Restated Credit Agreement of Regency Gas Services LLC
10.22*	Form of Indemnification Agreement between Regency GP LLC and Indemnities
10.23*	Financial Advisory Agreement
10.24*	Monitoring and Oversight Agreement
10.25*	Form of Omnibus Agreement
10.26**	Form of Fourth Amended and Restated Credit Agreement of Regency Gas Services LP
12.1	Computation of Ratio of Earnings to Fixed Charges
14.1	Code of Business Conduct
21.1	List of Subsidiaries of Regency Energy Partners LP
23.1	Consent of Deloitte & Touche LLP
24.1	Form by Power of Attorney
31.1	Certifications pursuant to Rule 13a-14(a).
31.2	Certifications pursuant to Rule 13a-14(a).
32.1	Certifications pursuant to Section 1350.
32.2	Certifications pursuant to Section 1350.
99.1	Balance Sheet of Regency GP LP, the general partner of the registrant

* Incorporated by reference to the comparably numbered exhibit to the registrant s registration statement on Form S-1 (File No. 333-128332).

** Incorporated by reference to the registrant s current report on Form 8-K dated August 14, 2006.

*** Incorporated by reference to the registrant s current report on Form 8-K dated September 21, 2006.

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

Incorporated by reference to the signature page of this filing.

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Index to Consolidated Financial Statements

Report of Independent Registered Public Accounting Firm	F-2
Consolidated Balance Sheets as of December 31, 2006 and 2005	F-3
Consolidated Statements of Operations for the years ended December 31, 2006 and 2005, the period from acquisition (December 1, 2004) to December 31, 2004, and the period from January 1, 2004 to November 30, 2004	F-4
Consolidated Statement of Member Interest and Partners Capital for the years ended December 31, 2006 and 2005, the period from acquisition (December 1, 2004) to December 31, 2004, and the period from January 1, 2004 to November 30, 2004	F-5
Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2006 and 2005, the period from acquisition (December 1, 2004) to December 31, 2004, and the period from January 1, 2004 to November 30, 2004	F-6
Consolidated Statements of Cash Flows for the years ended December 31, 2006 and 2005, the period from acquisition (December 1, 2004) to December 31, 2004, and the period from January 1, 2004 to November 30, 2004	F-7
Notes to the Consolidated Financial Statements	F-8

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Regency GP LLC and Unitholders of Regency Energy Partners LP:

We have audited the accompanying consolidated balance sheets of Regency Energy Partners LP and subsidiaries (the Partnership) as of December 31, 2006 and 2005, and the related consolidated statements of operations, member interest and partners capital, comprehensive income (loss) and cash flows, for the years ended December 31, 2006 and 2005, the period from acquisition date (December 1, 2004) to December 31, 2004, and Regency LLC Predecessor for the period from January 1, 2004 to November 30, 2004. These financial statements are the responsibility of the Partnership s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Partnership is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2006 and 2005, and the results of the Partnership s operations and cash flows for the years ended December 31, 2006 and 2005, the period from acquisition date (December 1, 2004) to December 31, 2004 and the results of Regency LLC Predecessor s operations and cash flows for the period from January 1, 2004 to November 30, 2004, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1, the Partnership accounted for its acquisition of TexStar Field Services, L.P. and its general partner, TexStar GP, LLC as acquisitions of entities under common control in a manner similar to a pooling of interests.

/s/ Deloitte & Touche LLP

Dallas, Texas
March 29, 2007

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Regency Energy Partners LP

Consolidated Balance Sheets

	December 31, 2006	December 31, 2005
	(In thousands except unit data)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 9,139	$ 3,686
Restricted cash	5,782	6,033
Accounts receivable, net of allowance of $181 in 2006 and $169 in 2005	96,993	91,968
Related party receivables	755	274
Assets from risk management activities	2,126	1,717
Other current assets	5,279	5,383
Total current assets	120,074	109,061
Property, plant and equipment:		
Gas plants and buildings	103,490	89,431
Gathering and transmission systems	529,776	482,423
Other property, plant and equipment	73,861	42,418
Construction in progress	85,277	17,426
Total property, plant and equipment	792,404	631,698
Less accumulated depreciation	(58,370)	(22,541)
Property, plant and equipment, net	734,034	609,157
Other assets:		
Intangible assets, net of amortization of $4,676 in 2006 and $2,029 in 2005	76,923	16,370
Long-term assets from risk management activities	1,674	1,333
Other, net of amortization on debt issuance costs of $946 in 2006 and $305 in 2005	17,212	7,275
Investments in unconsolidated subsidiaries	5,616	5,992
Goodwill	57,552	57,552
Total other assets	158,977	88,522
TOTAL ASSETS	$ 1,013,085	$ 806,740
LIABILITIES & PARTNERS CAPITAL OR MEMBER INTEREST		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 117,254	$ 116,997
Related party payables	280	3,380
Current portion of long term debt		700

Escrow payable	5,783	5,533
Accrued taxes payable	2,758	2,266
Liabilities from risk management activities	3,647	11,312
Other current liabilities	5,592	2,445
Total current liabilities	135,314	142,633
Long-term liabilities from risk management activities	145	4,895
Other long-term liabilities	269	
Long-term debt	664,700	428,250
Commitments and contingencies		
Partners Capital or Member Interest:		
Member interest		241,924
Common units (21,969,480 units authorized and 19,620,396 units issued and outstanding at December 31, 2006)	42,192	
Class B common units (5,173,189 units authorized, issued and outstanding at December 31, 2006)	60,671	
Class C common units (2,857,143 units authorized, issued and outstanding at December 31, 2006)	59,992	
Subordinated units (19,103,896 units authorized, issued and outstanding at December 31, 2006)	43,240	
General partner interest	5,543	
Accumulated other comprehensive income (loss)	1,019	(10,962)
Total partners capital or member interest	212,657	230,962
TOTAL LIABILITIES & PARTNERS CAPITAL OR MEMBER INTEREST	$ 1,013,085	$ 806,740

See accompanying notes to consolidated financial statements

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Regency Energy Partners LP

Consolidated Statements of Operations

	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
	(In thousands except unit data and per unit data)			
REVENUE				
Gas sales	$ 560,620	$ 506,278	$ 32,616	$ 279,582
NGL sales	256,672	183,073	11,890	123,827
Gathering, transportation and other fees	60,911	26,735	1,943	19,016
Related party revenues	2,160	833	16	
Net unrealized and realized gain/(loss) from risk management activities	(7,709)	(22,243)	322	
Other	24,211	14,725	1,070	9,896
Total revenue	896,865	709,401	47,857	432,321
OPERATING COSTS AND EXPENSES				
Cost of gas and liquids	738,816	632,342	40,987	362,762
Related party expenses	1,630	523		
Operation and maintenance	39,496	24,291	1,819	17,786
General and administrative	22,826	15,039	645	6,571
Management services termination fee	12,542			
Transaction expenses	2,041			7,003
Depreciation and amortization	39,654	23,171	1,661	10,129
Total operating costs and expenses	857,005	695,366	45,112	404,251
OPERATING INCOME	39,860	14,035	2,745	28,070
OTHER INCOME AND DEDUCTIONS				
Interest expense, net	(37,182)	(17,880)	(1,335)	(5,097)
Equity income	532	312	56	
Loss on debt refinancing	(10,761)	(8,480)		(3,022)
Other income and deductions, net	307	421	8	186
Total other income and deductions	(47,104)	(25,627)	(1,271)	(7,933)
NET INCOME (LOSS) FROM CONTINUING OPERATIONS	(7,244)	(11,592)	1,474	20,137
DISCONTINUED OPERATIONS				
Income (loss) from operations of Regency Gas Treating LP (including gain on disposal		732		(121)

of $626)

NET INCOME (LOSS)	$ (7,244)	$ (10,860)	$ 1,474	$ 20,016
Less:				
Net income from January 1-31, 2006	1,564			
Net loss for partners	$ (8,808)			
General partner s interest	(176)			
Limited partners interest	(8,632)			
Basic and diluted earnings per unit:				
Net loss allocated to common units	$ (4,003)			
Weighted average number of common units outstanding	19,103,896			
Loss per common unit	$ (0.21)			
Distributions declared per unit	$ 0.94			
Net loss allocated to subordinated units	$ (4,003)			
Weighted average number of subordinated units outstanding	19,103,896			
Loss per subordinated unit	$ (0.21)			
Distributions declared per unit	$ 0.94			
Net loss allocated to Class B common units	$ (626)			
Weighted average number of units outstanding	5,173,189			
Loss per Class B common unit	$ (0.12)			
Distributions declared per unit	$			
Net loss allocated to Class C common units	$			
Weighted average number of units outstanding	871,817			
Loss per Class C common unit	$			
Distributions declared per unit	$			

See accompanying notes to consolidated financial statements

Regency Energy Partners LP

Consolidated Statement of Member Interest and Partners Capital

	Units										Accumulated
				Subor-	Member	Common	Class B	Class C	Subordinated	General Partner	Other Comprehensive Income
	Common	Class B	Class C	dinated	Interest	Unitholders	Unitholders	Unitholders	Unitholders	Interest	(Loss)
					(In thousands except unit data)						
c											
2003					$ 59,856	$	$	$	$	$	$
est					10,000						
r the 4 to 2004					20,016						
est					(89,872)						
cember 1,											
rgy											
ion apital					171,000						
l					4,962						
butions					4,500						
r the led 2004					1,474						
2004					181,936						
butions					72,000						
fixed n ol in orical					(1,152)						
e year					(10,860)						
ber 31,											

fair flow ain							(16,502)
							5,540
2005			241,924				(10,962)
rough 06			1,564				
fair flow ain							2,581
							616
006			243,488				(7,765)
f net	5,353,896	19,103,896	(182,320)	89,337	89,337	3,646	
IPO, e costs	13,750,000			125,907	125,907	5,139	
from er on	1,400,000			26,163			
t option o HM ors	(1,400,000)			(26,163)			
t to HM rs				(119,441)			