Regency Energy Partners LP
Form 10-K
February 29, 2008

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, 2007
	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: 000-51757

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 þ No o
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, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer, accelerated filer and small reporting company" in Rule 12b-2 of the Exchange Act. Large accelerated filer þ Accelerated filer o Non-accelerated filer (Do not check if a smaller reporting company) o Smaller reporting company o
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, 2007, the aggregate market value of the registrant's common stock held by non-affiliates of the registrant was $1,004,269,000 based on the closing sale price as reported on the NASDAQ Stock Market LLC.

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

Class	Outstanding at February 7, 2008
Common Units	40,704,020
Subordinated Units	19,103,896
Class D Common Units	7,276,506
Class E Common Units	4,701,034

DOCUMENTS INCORPORATED BY REFERENCE

None

REGENCY ENERGY PARTNERS LP
ANNUAL REPORT ON FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2007

TABLE OF CONTENTS

Table of Contents

Introductory Statement

References in this report to the "Partnership," "we," "our," "us" and similar terms, when used in an historical 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. We use the following definitions in this annual report on Form 10-K:

Name	Definition or Description
ASC	ASC Hugoton LLC, an affiliate of GECC
BBE	BlackBrush Energy, Inc.
Bbls/d	Barrels per day
BBOG	BlackBrush Oil & Gas, LP
Bcf	One billion cubic feet
Bcf/d	One billion cubic feet per day
BP	BP America Production Co., a wholly-owned subsidiary of BP plc.
BTU	A unit of energy needed to raise the temperature of one pound of water by one degree Fahrenheit
CDM	CDM Resource Management, Ltd.
CDM GP	CDM OLP GP, LLC, the sole general partner of CDM
CDM LP	CDMR Holdings, LLC, the sole limited partner of CDM
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
CFTC	Commodities Futures Trading Commission
DOT	U.S. Department of Transportation
EIA	Energy Information Administration
Enbridge	Enbridge Pipelines (NE Texas), LP, Enbridge Pipeline (Texas Interstate), LP and Enbridge Pipelines (Texas Gathering), LP
EnergyOne	FrontStreet EnergyOne LLC
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FrontStreet	FrontStreet Hugoton LLC
Fund V	Hicks, Muse, Tate & Furst Equity Fund V, L.P.
GAAP	Accounting principles generally accepted in the United States
GE	General Electric Company
GE EFS	General Electric Energy Financial Services, a unit of GECC, combined with Regency GP Acquirer LP and Regency LP Acquirer LP
GECC	General Electric Capital Corporation, an indirect wholly owned subsidiary of GE
General Partner	Regency GP LP, the general partner of the Partnership, or Regency GP LLC, the general partner of Regency GP LP, which effectively manages the business and affairs of the Partnership
GSTC	Gulf States Transmission Corporation
HLPSA	Hazardous Liquid Pipeline Safety Act
HM Capital	HM Capital Partners LLC
HM Capital Investors	Regency Acquisition LP, HMTF Regency L.P., HM Capital and funds managed by HM Capital, including Fund V, and certain co-investors, including some of the directors and officers of the Managing GP
HMTF Gas Partners	HMTF Gas Partners II, LP
HMTF Regency	HMTF Regency L.P.
ICA	Interstate Commerce Act

IRS	Internal Revenue Service
LIBOR	London Interbank Offered Rate
MMbtu	One million BTUs
Mmbtu/d	One million BTUs per day
MMcf	One million cubic feet
MMcf/d	One million cubic feet per day
MQD	Minimum Quarterly Distribution
NGA	Natural Gas Act of 1938
NGLs	Natural gas liquids
NGPA	Natural Gas Policy Act of 1978
NGPSA	Natural Gas Pipeline Safety Act of 1968, as amended
NPDES	National Pollutant Discharge Elimination System
NASDAQ	Nasdaq Stock Market, LLC
NYMEX	New York Mercantile Exchange
OSHA	Occupational Safety and Health Act
Partnership	Regency Energy Partners LP
Pueblo	Pueblo Midstream Gas Corporation
RCRA	Resource Conservation and Recovery Act
RGS	Regency Gas Services LLC
RIGS	Regency Intrastate Gas LLC
SEC	Securities and Exchange Commission
Tcf	One trillion cubic feet
Tcf/d	One trillion cubic feet per day
TexStar	TexStar Field Services, L.P. and its general partner, TexStar GP, LLC
TRRC	Texas Railroad Commission

Table of Contents

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," "forecast," "may" or similar expre 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.

Table of Contents

PART I

Item 1. Business

OVERVIEW. We are a growth-oriented publicly-traded Delaware limited partnership engaged in the gathering, processing, contract compression, marketing and transportation of natural gas and NGLs. We provide these services through systems located in Louisiana, Texas, Arkansas, and the mid-continent region of the United States, which includes Kansas and Oklahoma. We were formed in 2005.

We divide our operations into three business segments:

§ Gathering and Processing: 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 NGLs from the raw natural gas and selling or delivering the pipeline-quality natural gas and NGLs to various markets and pipeline systems;

§ Transportation: We deliver natural gas from northwest Louisiana to more favorable markets in northeast Louisiana through our 320-mile Regency Intrastate Pipeline system; and

§ Contract Compression: On January 15, 2008, we acquired CDM, which provides customers with turn-key natural gas compression services.

All of our midstream 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 a strong balance sheet. We intend to achieve this by executing the following strategies:

§ Implementing cost-effective organic growth opportunities. We intend to build natural gas gathering assets, processing facilities, field compression, 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.

§ 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.

§ Continuing to reduce our exposure to commodity price risk. We operate our business in a manner designed to allow us to generate stable cash flows while mitigating the impact of fluctuations in commodity prices.

§ Utilizing our relationship with GE EFS to facilitate acquisitions from third parties. We intend to pursue strategic acquisitions of midstream assets from third parties 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. We also intend to pursue opportunities in new regions with significant natural gas reserves and high levels of drilling activity. We believe our relationship with GE EFS will provide increased access to such opportunities.

§ Pursuing strategic acquisitions of midstream assets from GE EFS. GE EFS's energy asset base is considerably larger than our own and includes midstream assets that we believe are strategically aligned with our existing operations or provide attractive operations in new regions. GE EFS does not have any obligation to sell assets to us. On January 8, 2008, however, we acquired FrontStreet, which owns a gas gathering system located in Kansas and Oklahoma, from affiliates of GECC.

§ Improving our credit ratings. We are committed to achieving an investment grade rating on our debt. Our current credit ratings are BB- and Ba3.

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

- § Our acquisition strategy and growth opportunities will benefit from our affiliation with GE EFS. As indicated above, we believe our affiliation with GE EFS enhances our ability to consummate accretive acquisitions and capitalize on market opportunities.
- § We have the financial flexibility and adequate access to capital to pursue acquisition and organic growth opportunities. We remain committed to maintaining a capital structure that will afford us the financial strength to fund expansion projects and other attractive investment opportunities. We believe our relationship with GE increases our access to capital and enables us to pursue strategic opportunities that we might otherwise be unable to pursue. In addition, we have sufficient liquidity under our credit facility to fund our near term growth capital requirements.
- § 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 in Kansas and Oklahoma, the Barnett Shale basin in north Texas, 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 experiencing high 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.

Table of Contents

§ We have a modern and efficient contract compressor fleet. Our highly standardized compressor fleet provides us with significant operational efficiencies and flexibility. At December 31, 2007, 73 percent of the total available horsepower in our contract compression segment was purchased new since December 31, 2003. We believe the young age and overall composition of our compressor fleet will result in fewer mechanical failures, lower fuel usage (a direct cost savings for our customers), and reduced environmental emissions. In addition, in developing and maintaining our standardized fleet, we have acquired increased technical proficiency in predictive and preventive maintenance and overhaul operations on our equipment, which helps us to achieve our mechanical availability commitments. We guarantee our customers 98 percent mechanical availability of our compression units for land installations and 96 percent mechanical availability for over-water installations.

§ Our large horsepower contract compression installations have long-term commitments and provide stable, fee-based cash flows. The large horsepower applications on which we focus in our contract compression business segment generally result in long-term installations with our customers, which we believe improves the stability of our cash flows. Our contracts generally have initial terms ranging from one to five years. We charge our customers either a fixed monthly fee for our compression services, regardless of the volume of natural gas we compress in that month, or a fee based on the volume of natural gas compressed per month.

§ Our Regency Intrastate Pipeline System provides us with significant fee-based transportation through-put volumes and cash flow. The Regency Intrastate Pipeline 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 an experienced, knowledgeable management team with a proven track record. Our senior management team 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 management team have a substantial economic interest in us through an indirect 8.2 percent economic interest in the General Partner and a 1.6 percent limited partner interest.

RECENT DEVELOPMENTS

Acquisition of Nexus. On February 22, 2008, we entered into an Agreement and Plan of Merger (the "Nexus Merger Agreement") with Nexus Gas Partners, LLC, a Delaware limited liability company ("Nexus Member"), and Nexus Gas Holdings, LLC, a Delaware limited liability company ("Nexus") ("Nexus Acquisition"). The aggregate consideration to be paid is $85,000,000 in cash, subject to adjustment pursuant to customary closing adjustments. Nexus is a midstream provider of natural gas gathering, dehydration and compression services for producers in DeSoto Parish, La., and Shelby County, Texas. The Nexus gathering system consists of 80 miles of low- and high-pressure gathering pipelines and is currently gathering more than 110 MMCF per day from approximately 500 wells. In addition, upon consummation of the Nexus Acquisition, we will acquire Nexus' rights under a Purchase and Sale Agreement (the "Sonat Agreement") between Nexus and Southern Natural Gas Company ("Sonat"). Pursuant to the Sonat Agreement Nexus will purchase 136 miles of pipeline from Sonat that would enable the Nexus gathering system to be integrated into our north Louisiana asset base (the "Sonat Acquisition"). The Sonat Acquisition is subject to abandonment approval by the FERC and other customary closing conditions. Upon the closing of the Sonat Acquisition, we will pay Sonat $28,000,000, and, if the closing occurs on or prior to March 1, 2010, on certain terms and conditions as provided in the Merger Agreement, we will make an additional payment of $25,000,000 to the Nexus Member.

In connection with the closing of the Merger, $8,500,000 will be deposited with an escrow agent to secure certain indemnification obligations of Member under the Merger Agreement. The escrow will remain in place for one year after the closing of the Merger, and the balance of the escrow upon termination of the escrow (net of any pending claims) will be released to Member.

The Nexus Acquisition is subject to approval under the Hart-Scott-Rodino Antitrust Improvements Act and other customary closing conditions. The closing is expected to occur in late first quarter or early second quarter 2008. We anticipate funding the Merger consideration through borrowings under the existing revolving credit facility.

Acquisition of CDM. On January 15, 2008, we acquired CDM for $695,314,000. The total purchase price, subject to customary post-closing adjustments, paid for the partnership interests of CDM consisted of (1) the issuance of an aggregate of 7,276,506 Class D common units of the Partnership, which were valued at $216,869,000, (2) the payment of an aggregate of $161,945,000 in cash to the CDM Partners, and (3) the assumption of $316,500,000 in CDM's debt obligations. Of those Class D common units issued, 4,197,303 Class D common units were deposited with an escrow agent pursuant to an escrow agreement. CDM provides customers with turn-key natural gas contract compression services to maximize their natural gas and crude oil production, throughput, and cash flow in Texas, Louisiana, and Arkansas. CDM's integrated solutions include a comprehensive assessment of a customer's natural gas contract compression needs and the design and installation of a compression system that addresses those particular field wide needs. CDM is responsible for the installation and ongoing operation, service, and repair of compressors, which we modify as necessary to adapt to our customers' changing operating conditions. The CDM acquisition provides the Partnership with stable, fee based cash flows, a source of long-term organic growth projects, and provides synergies with the Partnership's existing operations. CDM's experienced management team, retained by us to operate our contract compression segment, has demonstrated an ability to deliver strong organic growth since its inception. CDM's contract compression services will be reported as a separate business segment from the date of acquisition forward and will comprise the entire business segment.

Table of Contents

Amendments to the Fourth Amended and Restated Revolving Credit Facility. We have amended our credit agreement three times (September 28, 2007, January 15, 2008, and February 13, 2008) to increase commitments under our revolving credit facility to $900,000,000. The availability for letters of credit is $100,000,000. We also have the option to request an additional $250,000,000 in revolving commitments with 10 business days written notice 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. These amendments were executed to primarily provide funding for organic growth projects and acquisitions.

Acquisition of FrontStreet. On January 7, 2008, the Partnership acquired all the outstanding equity (the "FrontStreet Acquisition") of FrontStreet from ASC (an affiliate of GECC) and EnergyOne for $146,766,000. The total purchase price, subject to customary post-closing adjustments, paid by the Partnership for FrontStreet consisted of (1) the issuance of 4,701,034 Class E common units of the Partnership to ASC, which were valued at $135,014,000 and (2) the payment of $11,752,000 in cash to EnergyOne. FrontStreet owns a gas gathering system located in Kansas and Oklahoma, which is operated by a third party. FrontStreet's gas gathering system has 63,500 horsepower and 1,875 miles of pipeline extending over nine counties in Kansas and Oklahoma. The FrontStreet acquisition provides the Partnership with stable, fee based cash flows and is expected to be immediately accretive to our unitholders.

Equity Offering. On July 26, 2007, we closed an underwritten public offering of 10,000,000 common units for $32.05 per unit and, on July 31, 2007, the underwriters exercised their option to purchase 1,500,000 additional common units. We received net proceeds of $353,832,000 from these offerings. We used a portion of these proceeds to repay amounts outstanding under the term ($50,000,000) and revolving credit facility ($178,930,000). With the remaining proceeds and additional borrowings under the revolving credit facility, the Partnership repurchased $192,500,000, or 35 percent, of its outstanding senior notes which required us to pay an early redemption penalty of $16,122,000 in August 2007.

GE EFS acquisition of HM Capital's interests in us and resulting change in control. On June 18, 2007, Regency GP Acquirer LP, an indirect subsidiary of GECC, acquired 91.3 percent of both the member interest in the General Partner and the outstanding limited partner interests in the General Partner from an affiliate of HM Capital Partners. Concurrently, Regency LP Acquirer LP, another indirect subsidiary of GECC, acquired 17,763,809 of the outstanding subordinated units, exclusive of 1,222,717 subordinated units which were owned directly or indirectly by certain members of the Partnership's management team. As a part of this acquisition, affiliates of HM Capital Partners entered into an agreement not to sell or otherwise distribute 4,692,471 of the Partnership's common units retained by it for a period of 180 days. In addition, a separate affiliate of HM Capital Partners entered into an agreement not to sell or otherwise distribute 3,406,099 of the Partnership's common units retained by it for a period of one year.

GE Energy Financial Services is a unit of GECC which is an indirect wholly owned subsidiary of GE. For simplicity, we refer to Regency GP Acquirer LP, Regency LP Acquirer LP and GE Energy Financial Services collectively as "GE EFS." Concurrent with the Partnership's issuance of common units in July and August 2007, GE EFS and certain members of the Partnership's management made a capital contribution aggregating to $7,735,000 to maintain the General Partner's two percent interest in the Partnership.

Concurrent with the GE EFS acquisition of HM Capital's interest in us, eight members of the Partnership's senior management, together with two independent directors, entered into an agreement to sell an aggregate of 1,344,551 subordinated units for a total consideration of $25,544,000 or $24.00 per unit. Additionally, GE EFS entered into a subscription agreement with four officers and certain other management of the Partnership whereby these individuals acquired an 8.2 percent indirect economic interest in the General Partner.

The Partnership was not required to record any adjustments to reflect GE EFS's acquisition of the HM Capital Partners' interest in the Partnership or the related transactions (together, referred to as "GE EFS Acquisition").

INDUSTRY OVERVIEW

General. 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. It consists of natural gas gathering, compression, dehydration, processing and treating, fractionation, marketing and transportation. 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 their components, such as ethane, propane, butane, isobutane and natural gasoline. The NGL components are then sold to end users.

Table of Contents

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

Overview of U.S. market. According to the EIA, the midstream natural gas industry in the United States includes approximately 530 processing plants that process approximately 40 Bcf of natural gas per day and produce approximately 73 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 21.8 Tcf in 2006 to 24.3 Tcf in 2016, representing an average annual growth rate of 1.1 percent, with a slight decrease in consumption through the year 2030. 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 18.9 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. We operate more than 700,000 horsepower of compression in Texas, Louisiana, Oklahoma, Kansas and Arkansas.

Amine treating. The amine treating process involves a continuous circulation of a liquid chemical called amine that physically contacts with the natural gas. Amine has a chemical affinity for hydrogen sulfide and carbon dioxide that allows it to absorb these impurities from the gas. After mixing, gas and amine are separated, and the impurities are removed from the amine by heating. The treating plants are sized by the amine circulation capacity in terms of gallons per minute. We own and operate natural gas processing and/or treating plants in five geographic regions.

Processing. Natural gas processing involves the separation of natural gas into pipeline quality natural gas and a mixed NGL stream. The principal component of natural gas is methane, but most natural gas also contains varying amounts of heavier hydrocarbon components, or NGLs. Natural gas is described as lean or rich depending on its content of NGLs. Most natural gas produced by a well is not suitable for long-haul pipeline transportation or commercial use because it contains NGLs and impurities. Natural gas processing not only removes unwanted NGLs that would interfere with pipeline transportation or use of the natural gas, but also extracts hydrocarbon liquids that can have higher value as NGLs. Removal and separation of individual hydrocarbons by processing is possible because of differences in weight, boiling point, vapor pressure and other physical characteristics. 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, normal 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 natural 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.

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 interstate pipeline that extends from Harrison County, Texas to Caddo Parish, Louisiana.

Table of Contents

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.

All raw natural gas flowing through our gathering and processing facilities is supplied under gathering and processing contracts having 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."

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, 2007.

Region	Pipeline Length (Miles)	Plants	Compression (Horsepower)	Through-put Volume Capacity (MMcf/d)
North Louisiana	600	4	39,100	790
East Texas	371	1	25,665	215
South Texas	623	2	27,828	555
West Texas	750	1	47,000	325
Mid-Continent	3,470	1	105,630	437
Total	5,814	9	245,223	2,322

The following map depicts the geographic areas of our operations.

Table of Contents

North Louisiana Region. Our north Louisiana region includes:

- § the Dubach and Lisbon processing plants;
- § 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
- § the Elm Grove and Dubberly refrigeration plants.

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. This area has 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 it 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 and Lisbon Processing Plants. The Dubach processing plant is a cryogenic natural gas processing plant that processes raw natural gas gathered on the Dubach and Calhoun gathering systems. The Lisbon plant is a cryogenic natural gas processing plant that processes raw natural gas gathered on the Lisbon gathering system. These plants were acquired by us in 2003, were originally constructed in 1980 and were reassembled on their present locations in 1994 and 1996, respectively.

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 gathering assets gather, compress, and dehydrate natural gas. Natural gas produced in this region contains high levels of hydrogen sulfide. 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
- § the Como Gathering System, a smaller integrated natural gas gathering and processing system located in Franklin, Wood, Hopkins and Rains Counties.

Both the Eustace and Como gathering systems deliver natural gas to into the Eustace processing plant that is equipped with a sulfur removal unit.

Natural Gas Supply. The natural gas supply for our east Texas gathering systems is derived primarily from natural gas wells located in a mature basin that 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 an amine treating unit, a cryogenic NGL recovery unit, a nitrogen rejection unit, and a liquid sulfur recovery unit. This plant removes hydrogen sulfide, carbon dioxide and nitrogen from the natural gas stream, recovers NGLs and condensate, delivers pipeline quality gas at the plant outlet and produces sulfur.

South Texas Region. The south Texas gathering assets gather, compress, and dehydrate natural gas. Some of the natural gas produced in this region can have significant hydrogen sulfide and carbon dioxide content. These systems are connected to processing and treating facilities that include an acid gas reinjection well. Our south Texas region primarily includes the following natural gas gathering systems:

§ the LaSalle Gathering System, a large natural gas gathering system located in LaSalle and Webb counties. Gas from this system is processed by a third party.
§ the Pueblo Gathering System, a large integrated natural gas gathering, treating, and processing system located in Karnes and Atascosa counties. Gas from this system is treated and processed at our Fashing Plant. We have plans to connect this system to our Tilden treating plant during 2008;
§ the Tilden Gathering System, a large integrated natural gas gathering and treating system located in McMullen, Atascosa, Frio and LaSalle Counties in south Texas and flows into the Tilden treating plant; and
§ the Palafox Gathering System, a small gathering system located in Dimmitt and Webb counties, Texas. The natural gas gathered by this system is delivered to a third party for processing.

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

Tilden Treating Plant. The Tilden Treating Plant is a natural gas treating plant constructed on 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. An additional 55 MMcf/d amine treating unit is 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 reinjects acid gas.

West Texas Region. 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. Our west Texas region includes the Waha gathering system and the Waha processing plant.

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 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.

Table of Contents

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 typically 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 which removes carbon dioxide and hydrogen sulfide from raw natural gas gathered in our Waha gathering system before moving the natural gas to the processing plant. The acid gas is reinjected.

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.

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. These mature basins have continued to 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. On January 7, 2008, the Partnership completed its acquisition of FrontStreet which owns the Hugoton gathering system, consisting of five compressor stations with over 63,500 horsepower and 1,875 miles of pipeline extending over nine counties in Kansas and Oklahoma. This system is operated by a third party.

Lakin Gathering System. The Lakin 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 Lakin gathering system is delivered to a third party’s processing plant.

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 primarily located in Morton and Stanton Counties in southwestern Kansas. 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, which is currently idle, 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

Regency Intrastate Pipeline. We own and operate a 320-mile intrastate natural gas pipeline system, known as the Regency Intrastate Pipeline system, in north Louisiana extending from Caddo Parish to Franklin Parish in northern Louisiana. This system, with pipeline ranging from 12 to 30 inches in diameter, includes total system capacity of 910 MMcf/d, 28,375 horsepower of compression and our Haughton Plant, a 35 MMcf/d refrigeration plant. 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 three of the four largest natural gas producing fields in 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.

Gulf States Transmission. Our interstate pipeline consists of 10 miles of 12 and 20 inch diameter pipeline that extends from Harrison County, Texas to Caddo Parish, Louisiana. The pipeline has a FERC certificated capacity of 150 MMcf/d.

On February 6, 2008, one of the interstate pipelines, Columbia Gulf, which our RIGS pipeline interconnects with, lost approximately 68,000 horsepower of compression due to a tornado. We have not experienced a material impact to our operations or results of operations. We continue to monitor this situation and will modify our operations if necessary.

Table of Contents

CONTRACT COMPRESSION OPERATIONS

The natural gas contract compression services we provide, subsequent to our acquisition of CDM, include designing, sourcing, owning, insuring, installing, operating, servicing, repairing, and maintaining compressors and related equipment for which we guarantee our customers 98 percent mechanical availability for land installations and 96 percent mechanical availability for over-water installations. We focus on meeting the complex requirements of field-wide compression applications, as opposed to targeting the compression needs of individual wells within a field. These field-wide applications include compression for natural gas gathering, natural gas lift for crude oil production and natural gas processing. We believe that we improve the stability of our cash flow by focusing on field-wide compression applications because such applications generally involve long-term installations of multiple large horsepower compression units. Our contract compression operations are primarily located in Texas, Louisiana, and Arkansas.

The following table set forth certain information regarding CDM's revenue generating natural gas compressor horsepower as of December 31, 2007.

Horsepower Range	Total Revenue Generating Horsepower	Percentage of Revenue Generating Horsepower	Number of Units
0-499	41,958	7%	252
500-999	61,609	11%	99
1,000+	464,660	82%	307
	568,227	100%	658

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 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. 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 year ended December 31, 2007, purchases from KCS Resources, Inc. were 16 percent of the volumes underlying the cost of gas and liquids on our consolidated statement of operations.

For the above described contracts, the margin by product and percentage were as follows for the year ended December 31, 2007.

Margin by Product	Percent
Net Fee	43%
NGL	37
Gas	10
Condensate	8
Helium and Sulfur	2
Total	100%

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 the FERC with respect to transportation authorized under Section 311 of the 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 where 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.

Table of Contents

Contract Compression Contracts. We generally enter into a new contract with respect to each distinct application for which we will provide contract compression services. Our compression contracts typically have an initial term between one and five years, after which the contract continues on a month-to-month basis. Our customers pay either a fixed monthly fee, or a fee based on the volume of natural gas actually compressed. We are not responsible for acts of force majeure and our customers are generally required to pay our monthly fee for fixed fee contracts, or a minimum fee for throughput contracts, even during periods of limited or disrupted production. We are generally responsible for the costs and expenses associated with operation and maintenance of our compression equipment, such as providing necessary lubricants, although certain fees and expenses are the responsibility of the customer under the terms of their contracts. For example, all fuel gas is provided by our customers without cost to us, and in many cases customers are required to provide all water and electricity. We are also reimbursed by our customers for certain ancillary expenses such as trucking, crane and installation labor costs, depending on the terms agreed to in a particular contract.

COMPETITION

Gathering and Processing. The natural gas gathering, processing, contract compression, 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. Our major competitors in each region include:

§ North Louisiana: CenterPoint Energy Gas Marketing Company; 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, Enterprise Products Partners LP

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

Transportation. Competition in natural gas transportation is characterized by price of transportation, the nature of the markets accessible from a transportation pipeline and the type of service provided. 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.

Contract Compression. The natural gas contract compression services business is highly competitive. We face competition from large national and multinational companies with greater financial resources and, on a regional basis, from numerous smaller companies. Our main competitors in the natural gas contract compression business, based on horsepower, are Hanover Compressor Company, Universal Compression Holdings, Inc. (or Exterran Holdings, Inc. following its merger with Hanover Compressor Company), Universal Compression Partners, L.P., Compressor Systems, Inc., USA Compression and J-W Operating Company.

We believe that the superior mechanical availability of our standardized compressor fleet is the primary basis on which we compete and a significant distinguishing factor from our competition. All of our competitors attempt to compete on the basis of price. We believe our pricing has proven competitive because of the superior mechanical availability we deliver, the quality of our compression units, as well as the technical expertise we provide to our customers. We believe our focus on addressing customers’ more complex natural gas compression needs related primarily to field-wide compression applications differentiates us from many of our competitors who target smaller horsepower projects related to individual wellhead applications.

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;
- § manage our portfolio of contracts to reduce commodity price risk;
- § optimize our portfolio by active monitoring of basis, swing, and fractionation spread exposure; and
- § hedge a portion of our exposure to commodity prices.

As a consequence of our gathering and processing contract portfolio, we derive a portion of our earnings from a long position in NGLs, 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 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. We also hedge this commodity price risk by purchasing a series of swap contracts for individual NGLs. Our hedging position and needs to supplement or modify our position are closely monitored by the Risk Management Committee of the Board of Directors. 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.

Table of Contents

Our contract compression business does not have direct exposure to natural gas commodity price risk because we do not take title to the natural gas we compress and because the natural gas we use as fuel for our compressors is supplied by our customers without cost to us. Our indirect exposure to short-term volatility in natural gas and crude oil commodity prices is mitigated because natural gas and crude oil production, rather than exploration, is the primary demand driver for our contract compression services, and because our focus on field-wide applications reduces our dependence on individual well economics.

REGULATION

Industry Regulation

Intrastate Natural Gas Pipeline Regulation. Pursuant to Section 311 of the NGPAS, RIGS transports interstate natural gas in Louisiana for many of its shippers. To the extent that our Regency Intrastate Pipeline system transports natural gas in interstate service, its rates, terms and conditions of service are subject to the jurisdiction of the FERC. 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 the FERC are generally analogous to the cost-based rates that the FERC deems "just and reasonable" for interstate pipelines under the NGA. RIGS is required to file triennial rate petitions either justifying its existing rates or requesting new rates. RIGS' most recent FERC-approved Section 311 maximum rates were established in 2005 effective from May 1, 2005 to May 1, 2008. These rates were set for firm transportation at $0.15 per MMBtu reservation charge, with a $0.05 MMBtu daily 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. Any failure on our part:

- to observe the service limitations applicable to transportation service under Section 311,
- to comply with the rates approved by the 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.

RIGS is also 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. 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. The distinction between FERC-regulated transmission facilities and intrastate facilities has been the subject of litigation, so the classification and regulation of RIGS as an intrastate pipeline may be subject to change based on future determinations by the FERC, the courts or the U.S. Congress.

FERC has adopted new market-monitoring and annual reporting regulations applicable to many intrastate pipelines. These regulations are intended to increase the transparency of wholesale energy markets, to protect the integrity of such markets, and to improve FERC's ability to assess market forces and detect market manipulation. Although these regulations are not final, the monitoring and annual reporting mandated by these regulations could require intrastate pipelines to incur increased costs and administrative burdens. FERC has also proposed to require both interstate and certain major non-interstate pipelines to post, on a daily basis, capacity, scheduled flow information and actual flow information, which regulations could subject us to further costs and administrative burdens.

Interstate Natural Gas Pipeline Regulation. The FERC also has broad regulatory authority over the business and operations of interstate natural gas pipelines, such as the pipeline owned by our subsidiary, 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. The 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;
§ market manipulation in connection with interstate sales, purchases, or transportation of natural gas and
§ information posting requirements.

Any failure on our part to comply with the laws and regulations governing interstate transmission service could result in the imposition of administrative, civil and criminal penalties.

Table of Contents

Gathering Pipeline Regulation. Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of the FERC under the NGA. We own a number of natural gas pipelines that we believe meet the traditional tests that the FERC has used to establish a pipeline's status as a gatherer not subject to FERC jurisdiction. The distinction between FERC-regulated transmission facilities and federally unregulated gathering facilities is the subject of substantial, on-going litigation, so the classification and regulation of one or more of our gathering systems may be subject to change based on future determinations by the 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 other 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 the state level now that the FERC has allowed a number of interstate pipeline transmission companies to transfer formerly jurisdictional assets to gathering companies. For example, in 2006, the TRRC approved changes to its regulations governing transportation and gathering services performed by intrastate pipelines that prohibit such entities from unduly discriminating in favor of their affiliates.

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.

Regulation of NGL and Crude Oil Transportation. We have a pipeline in Louisiana that transports NGLs in interstate commerce pursuant to a FERC-approved tariff. Under the ICA, the Energy Policy Act of 1992, and rules and orders promulgated thereunder, the FERC regulates the tariff rates for interstate NGL transportation and imposes reporting and a number of other requirements. Our NGL transportation tariff is required to be just and reasonable and not unduly discriminatory or confer any undue preference. FERC has established an indexing system for transportation rates for oil, NGLs and other products that allows for an annual inflation-based increase in the cost of transporting these liquids to the shipper. The implementation of these regulations has not had a material adverse effect on our results of operations. Any failure on our part to comply with the laws and regulations governing interstate transmission of NGLs could result in the imposition of administrative, civil and criminal penalties. We also have a Texas common carrier pipeline that provides intrastate transportation of crude oil subject to a local tariff approved by and on file with the TRRC. This pipeline is subject to a number of TRRC regulatory requirements governing rates and terms and conditions of service.

Sales of Natural Gas. Our ability to sell gas in interstate markets is subject to FERC authority and its rules prohibiting natural gas market manipulation. 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. 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.

Sales of Liquids. Sales of crude oil, natural gas, condensate and NGLs are not currently regulated. Prices of these products are set by the market rather than by regulation.

Anti-Market Manipulation Requirements. Under the Energy Policy Act of 2005, FERC possesses regulatory oversight over natural gas markets, including the purchase, sale and transportation activities of non-interstate pipelines and other natural gas market participants. The CFTC also holds authority to monitor certain segments of the physical and futures energy commodities market pursuant to the Commodity Exchange Act. With regard to our physical purchases and sales of natural gas, NGLs and crude oil, our gathering or transportation of these energy commodities, and any related hedging activities that we undertake, we are required to observe these anti-market manipulation laws and related regulations enforced by FERC and/or the CFTC. These agencies hold substantial enforcement authority, including the ability to assess civil penalties of up to $1,000,000 per day per violation, to order disgorgement of profits and to recommend criminal penalties. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, sellers, royalty owners and taxing authorities.

Anti-terrorism Regulations. We may be subject to future anti-terrorism requirements of the DHS. The DHS has issued its National Infrastructure Protection Plan calling for broadened efforts to "reduce vulnerability, deter threats, and minimize the consequences of attacks and other incidents" as they relate to pipelines, processing facilities and other infrastructure. The precise parameters of DHS regulations and any related sector-specific requirements are not currently known, and there can be no guarantee that any final anti-terrorism rules that might be applicable to our facilities will not impose costs and administrative burdens on our operations.

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 formerly owned 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, 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 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 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.

Table of Contents

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.

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.

In January 2008, the Board of Directors of the General Partner and the Partnership signed a settlement of the El Paso environmental remediation. Under the settlement, El Paso will clean up and obtain "no further action" letters from the relevant state agencies for three owned Partnership facilities. El Paso is not obligated to clean up properties leased by the Partnership, but it indemnified the Partnership for pre-closing environmental liabilities at that site. All sites for which the Partnership made environmental claims against El Paso are either addressed in the settlement or have already been resolved. The Partnership will release all but $1,500,000 from the escrow fund maintained to secure El Paso's obligations. This amount will be further reduced per a specified schedule as El Paso completes its cleanups and the remainder will be released upon completion.

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 RGS 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, such as our processing plants and compression 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.

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 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.

Table of Contents

Employee Health and Safety. We are subject to the requirements of the federal 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 DOT, under the 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 interstate, intrastate and certain of our gathering pipelines are also are subject to regulation by the DOT under the NGPSA, which covers natural gas, crude oil, carbon dioxide, NGLs and petroleum products pipelines, and under the Pipeline Safety Improvement Act of 2002, as amended. Pursuant to these authorities, the DOT has established a series of rules which require pipeline operators to develop and implement “integrity management programs” for natural gas pipelines located in areas where the consequences of potential pipeline accidents pose the greatest risk to people and their property. Similar rules are also in place for operators of hazardous liquid pipelines. The DOT’s integrity management rules establish requirements relating to the design, installation, testing, construction, operation, inspection, replacement and management of pipeline facilities. We believe that our pipeline operations are in substantial compliance with applicable NGPSA requirements.

The states administer federal pipeline safety standards under the NGPSA and have the authority to conduct pipeline inspections, to investigate accidents, and to oversee compliance and enforcement, safety programs, and record maintenance and reporting. Congress, the DOT and individual states may pass additional 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.

TCEQ Notice of Enforcement. On February 15, 2008, the Texas Commission on Environmental Quality, or TCEQ, sent us a notice of enforcement, or NOE, relating to the air emissions at our Tilden processing plant. The NOE relates to 15 alleged violations occurring during the period from March 2006 through July 2007 of the emissions event reporting and recordkeeping requirements of the TCEQs rules. Specifically, it is alleged that one of our subsidiaries failed to report, using the TCEQ’s electronic data base for emissions events, 15 emissions events within 24 hours of the incident, as required. These events occurred during times of failure of the Tilden plant sulphur recovery unit or ancillary equipment and resulted in the flaring of acid gas. Of these events, one relates to an alleged release of nearly 6 million pounds of sulphur dioxide and 64,000 pounds of hydrogen sulphide, 11 related to less than 2,500 pounds of sulphur dioxide and three related to more than 2,500 and less than 40,000 pounds of sulphur dioxide (including two releases of 126 and 393 pounds of hydrogen sulphide). In 2007, the subsidiary completed construction of an acid gas reinjection unit at the Tilden plant and permanently shut down the Sulphur Recovery Unit

All these emission incidents were reported by means of fax or telephone to the TCEQ pursuant to an informal procedure established with the TCEQ by the prior owner of the Tilden plant and, indeed, the subsidiary paid the emission fines in connection with all the incidents. Using that procedure, all except one were timely. The TCEQ has, prior to our subsidiary acquiring the Tilden facility, established its electronic data base for emissions events, but the subsidiary did not report using that electronic facility. It is the failure to report each incident timely using the electronic reporting procedure that is the subject of the NOE. Representatives of the Partnership are scheduled to meet with the staff of the TCEQ in the near future regarding the NOE. Management of the General Partner does not expect the NOE to have a material adverse effect on its results of operations or financial condition.

EMPLOYEES

As of December 31, 2007, our General Partner employs 317 employees, of whom 182 are field operating employees and 135 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 General Partner is a party. Our General Partner believes that it has good relations with its employees. With our CDM acquisition, we now employ 609 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; we also file amendments to reports filed or furnished pursuant to Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934. References to our website addressed in this report are provided as a convenience and do not constitute, or should be viewed as, an incorporation by reference of the information contained on, or available through, the website. Therefore, such information should not be considered part of this report.

Table of Contents
ITEM 1A. Risk Factors
RISKS RELATED TO OUR BUSINESS

We may not have sufficient cash from operations to enable us to pay our current quarterly distribution following the establishment of cash reserves and payment of fees and expenses, including reimbursement of fees and expenses of our general partner.

We may not have sufficient available cash from operating surplus each quarter to pay our MQD. The amount of cash we can distribute on our units depends principally on the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

§ the fees we charge and the margins we realize for our services and sales;
§ the prices of, level of production of, and demand for natural gas and NGLs;
§ the volumes of natural gas we gather, process and transport;
§ the level of our operating costs, including reimbursement of fees and expenses of our general partner; and
§ prevailing economic conditions.

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

§ our debt service requirements;
§ fluctuations in our working capital needs;
§ our ability to borrow funds and access capital markets;
§ restrictions contained in our debt agreements;
§ the level of capital expenditures we make;
§ the cost of acquisitions, if any; and
§ the amount of cash reserves established by our general partner.

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

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

Integration of acquisitions with our business and operations is a complex, time consuming, and costly process. Failure to integrate acquisitions 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 past or future acquisitions. 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, such as the assets acquired in the CDM acquisition;
§ 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, growth or 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.

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 processing 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 our 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. 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.

Table of Contents

Our natural gas contract compression operations significantly depend upon the continued demand for and production of natural gas and crude oil. Demand may be affected by, among other factors, natural gas prices, crude oil prices, weather, demand for energy, and availability of alternative energy sources. Any prolonged, substantial reduction in the demand for natural gas or crude oil would, in all likelihood, depress the level of production activity and result in a decline in the demand for our contract compression services and products. Lower natural gas prices or crude oil prices over the long-term could result in a decline in the production of natural gas or crude oil, respectively, resulting in reduced demand for our natural gas contract compression services. Additionally, production from natural gas sources such as longer-lived tight sands, shales and coalbeds constitute an increasing percentage of our compression services business. Such sources are generally less economically feasible to produce in lower natural gas price environments, and a reduction in demand for natural gas or natural gas lift for crude oil may cause such sources of natural gas to be uneconomic to drill and produce, which could in turn negatively impact the demand for our services.

We depend on certain key producers and other customers for a significant portion of our supply of natural gas and contract compression revenue. The loss of, or reduction in, 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 and our contracts for compression services. These contracts have terms that 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. 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. For example, purchases from KCS Resources, Inc. made up 16 percent of the volumes underlying the cost of gas and liquids on our consolidated statement of operations during the year ended December 31, 2007.

Our contract compression segment depends on particular suppliers and is vulnerable to product shortages and price increases, which could have a negative impact on our results of operations.

The principal manufacturers of components for our natural gas compression equipment include Caterpillar, Inc. for engines, Air-X-Changers for coolers, and Ariel Corporation for compressors and frames. Our reliance on these suppliers involves several risks, including price increases and a potential inability to obtain an adequate supply of required components in a timely manner. We also rely primarily on two vendors, Spitzer Corp. and Standard Equipment Corp., to package and assemble our compression units. We do not have long-term contracts with these suppliers or packagers, and a partial or complete loss of certain of these sources could have a negative impact on our results of operations and could damage our customer relationships. In addition, since we expect any increase in component prices for compression equipment or packaging costs will be passed on to us, a significant increase in their pricing could have a negative impact on our results of operations.

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.

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 are 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. 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 fluctuates 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;

Table of Contents

- 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 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.

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 NGL prices, we have executed swap contracts settled against ethane, propane, normal butane, natural gasoline and west Texas intermediate crude market prices. We continually monitor our hedging and contract portfolio and expect to continue to adjust our hedge position as conditions warrant. Also, we may seek to limit our exposure to changes in interest rates by using financial derivative instruments and other hedging mechanisms from time to time. For more information about our risk management activities, please read "Item 7A — Quantitative and Qualitative Disclosures about Market Risk."

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

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

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 the completion of construction 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.

Table of Contents
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. 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.

The natural gas contract compression business is highly competitive, and there are low barriers to entry for individual projects. In addition, some of our competitors are large national and multinational companies that have greater financial and other resources than we do. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenue and cash flows could be adversely affected by the activities of our competitors and our customers. If our competitors substantially increase the resources they devote to the development and marketing of competitive services or substantially decrease the prices at which they offer their services, we may be unable to compete effectively. Some of these competitors may expand or construct newer or more powerful compressor fleets that would create additional competition for us. In addition, our customers that are significant producers of natural gas and crude oil may purchase and operate their own compressor fleets in lieu of using our natural gas contract compression services.

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

Our 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 extensive rains which could delay the construction of assets and extreme cold which can cause freezing of pipelines, limiting throughput; 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.

Table of Contents

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.

We may incur significant costs and liabilities as a result of pipeline integrity management program testing and any related pipeline repair, or preventative or remedial measures.

The DOT has adopted regulations requiring pipeline operators to develop integrity management programs for transportation pipelines and certain gathering lines located where a leak or rupture could do the most harm in “high consequence areas.” The regulations require operators to:

§ perform ongoing assessments of pipeline integrity;
§ identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
§ improve data collection, integration and analysis;
§ repair and remediate the pipeline as necessary; and
§ implement preventive and mitigating actions.

We currently estimate that we will incur costs of $1,200,000 between 2008 and 2010 to implement pipeline integrity management program testing along certain segments of our pipeline, as required by existing DOT regulations. This estimate does not include the costs, if any, for repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, which could be substantial.

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 and transportation 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.

Our interstate gas transportation operations, including Section 311 service performed by its intrastate pipelines, are subject to FERC regulation; failure to comply with applicable regulation, future changes in regulations or policies, or the establishment of more onerous terms and conditions applicable to interstate or Section 311 natural gas transportation service could adversely affect our business.

FERC has broad regulatory authority over the business and operations of interstate natural gas pipelines, such as the pipeline owned by our subsidiary, 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. In addition, FERC regulates the rates, terms and conditions of service with respect to Section 311 transportation service provided by RIGS. Any failure on our part to comply with applicable FERC administered statutes, rules, regulations and orders could, in the case of RIGS, result in an alteration of our jurisdictional status, or could result in the imposition of administrative, civil and criminal penalties, or both. In addition, FERC has authority to alter its rules, regulations and policies to comply with its statutory authority. We cannot give any assurance regarding the likely future regulations under which RIGS or GSTC will operate its interstate transportation business or the effect such regulation could have on our business, results of operations, or ability to make distributions.

Table of Contents

As a limited partnership entity, we may be disadvantaged in calculating its cost-of-service for rate-making purposes.

Under current policy applied under the NGA, the FERC permits interstate gas pipelines to include, in the cost-of-service used as the basis for calculating the pipeline's regulated rates, a tax allowance reflecting the actual or potential income tax liability on public utility income attributable to all partnership or limited liability company interests, if the ultimate owner of the interest has an actual or potential income tax liability on such income. Whether a pipeline's owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. In connection with its upcoming Section 311 rate case required to be initiated on or before May 1, RIGS may be required to demonstrate the extent to which inclusion of an income tax allowance in Regency's cost-of-service is permitted under the current income tax allowance policy. Although FERC's policy is generally favorable for pipelines that are organized as, or owned by, tax-pass-through entities, application of the policy in individual rate cases still entails rate risk due to the case-by-case review requirement. The specific terms and application of that policy remain subject to future refinement or change by FERC and the courts. Moreover, we cannot guarantee that this policy will not be altered in the future.

In addition, on July 19, 2007, FERC issued a proposed policy statement regarding the composition of proxy groups for determining the appropriate returns on equity for interstate natural gas and oil pipelines. The proposed policy statement would permit the inclusion of master limited partnerships (MLPs) in the proxy group for purposes of calculating returns on equity under the discounted cash flow analysis, a change from its prior view that MLPs had not been shown to be appropriate for such inclusion. Specifically, FERC proposes that MLPs may be included in the proxy group provided that the discounted cash flow analysis recognizes as distributions only the pipeline's reported earnings and not other sources of cash flow subject to distribution. According to the proposed policy statement, under the discounted cash flow analysis, the return on equity is calculated by adding the dividend or distribution yield (dividends divided by share/unit price) to the projected future growth rate of dividends or distributions (weighted one-third for long-term growth of the economy as a whole and two-thirds short term growth as determined by analysts' five-year forecasts for the pipeline). The determination of which MLPs should be included will be made on a case-by-case basis, after a review of whether an MLPs earnings have been stable over a multi-year period. FERC proposes to apply the final policy statement to all natural gas rate cases that have not completed the hearing phase as of the date FERC issues the final policy statement. Comments on the proposed policy statement were filed by numerous parties, and on January 8, 2008, FERC held a technical conference to discuss the proposed policy. FERC's proposed policy statement is subject to change based on filed comments and the technical conference. Therefore, we cannot predict the scope or outcome of the final policy statement. If the hearing phase of the Section 311 rate case RIGS is required to file by May 1, 2008, has not been completed as of the date FERC issues its final policy statement, and FERC determines to apply the policy statement to Section 311 transportation rates, application of the statement might affect RIGS ability to achieve a reasonable level of equity return in its Section 311 rate proceeding.

A change in the jurisdictional 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. However, with the passage of the Energy Policy Act of 2005, the FERC has sought to expand its oversight of natural gas purchasers, gatherers and intrastate pipelines by developing new market monitoring and market transparency rules. FERC recently issued a notice of proposed rulemaking that would require posting of available capacity, scheduled capacity and actual flows on non-interstate pipelines, including gathering companies and intrastate pipelines. We cannot predict the outcome of this proposed rulemaking or how the FERC will approach future 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. In such circumstances, the classification and regulation of some of our gathering or our intrastate transportation pipelines 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, which could adversely affect our business.

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.

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.

Table of Contents

There is inherent risk of the incurrence of environmental costs and liabilities in our business due to the necessity of handling natural gas and NGLs, 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 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.

Our leverage may limit our ability to borrow additional funds, make distributions, 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, 2007 was 51 percent. We will be prohibited from making cash distributions during an event of default under any of our indebtedness, and, in the case of the indenture under which our senior notes were issues, the failure to maintain a prescribed ratio of consolidated cash flows (as defined in the indenture) to interest expense.. Various limitations in our credit facility, as well as the indenture for our senior 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 otherwise realize fully 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 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.

The interest rate on our senior notes is fixed and the loans outstanding under our credit facility bear interest at a floating rate. 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.

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.

Our ability to manage and grow our business effectively may be adversely affected if our General Partner loses key management or operational personnel.

We depend on the continuing efforts of our executive officers. The departure of any of our executive officers could have a significant negative effect on our business, operating results, financial condition, and on our ability to compete effectively in the marketplace. Additionally, the General Partner's employees operate our business. Our General Partner's ability to hire, train, and retain qualified personnel will continue to be important and will become more challenging as we grow and if energy industry market conditions continue to be positive. When general industry conditions are good, the competition for experienced operational and field technicians increases as other energy and manufacturing companies' needs for the same personnel increases. Our ability to grow and perhaps even to continue our current level of service to our current customers will be adversely impacted if our General Partner is unable to successfully hire, train and retain these important personnel.

Table of Contents

Terrorist attacks, the threat of terrorist attacks, 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 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.

RISKS RELATED TO OUR STRUCTURE

GE EFS controls our general partner, which has sole responsibility for conducting our business and managing our operations.

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 owner, GE EFS. Conflicts of interest may arise between GE EFS, 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 GE EFS or affiliates of GECC 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 GE EFS, in resolving conflicts of interest;
§ our General Partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings and repayments of debt, issuance of additional partnership securities, and cash reserves, each of which can affect the amount of cash available for distribution;
§ our General Partner determines which costs incurred are reimbursable by us;
§ our partnership agreement does not restrict our General Partner from causing us to pay 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.

GE EFS and affiliates of GECC may compete directly with us.

GE EFS and affiliates of GECC are not prohibited from owning assets or engaging in businesses that compete directly or independently with us. GE EFS and affiliates of GECC currently own various midstream assets and conduct midstream businesses that may potentially compete with us. In addition, GE EFS and affiliates of GECC 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 common unitholders.

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. The reimbursement of expenses incurred by 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.

Table of Contents

Our partnership agreement contains provisions that reduce the standards to which our General Partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement:

- permits our General Partner to make a number of decisions in its individual capacity, as opposed to its capacity as our General Partner. This entitles our General Partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include the exercise of its limited call right, its voting rights with respect to the units it owns, its registration rights and its determination whether or not to consent to any merger or consolidation of the partnership;
- provides that our General Partner will not have any liability to us or our unitholders for decisions made in its capacity as a General Partner so long as it acted in good faith, meaning it believed the decision was in the best interests of our partnership;
- provides that our General Partner is entitled to make other decisions in "good faith" if it believes that the decision is in our best interests;
- provides generally that affiliated transactions and resolutions of conflicts of interest not approved by the conflicts committee of our General Partner and not involving a vote of unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or be “fair and reasonable” to us, as determined by our General Partner in good faith, and that, in determining whether a transaction or resolution is “fair and reasonable,” our General Partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us; and
- provides that our General Partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the General Partner or those other persons acted in bad faith or engaged in fraud or willful misconduct.

Any common unitholder is 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 do not elect our General Partner or its board of directors and 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 are 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. A vote of the holders of at least 66 2/3 percent of all outstanding units voting together as a single class is required to remove the General Partner. As of February 7, 2008, our General Partner owns 31.2 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 GE EFS 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 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 our 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 our General Partner 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.

Table of Contents

Certain of our investors may sell units in the public market, which could reduce the market price of our outstanding common units.

Pursuant to agreements with investors in private placements or acquisitions, we have filed registration statements on Form S-3 registering sales by selling unitholders of an aggregate of 11,881,000 of our common units, and have outstanding obligations to file registration statements with respect to 11,978,000 common units, including the 7,276,506 common units to be issued upon conversion of Class D units we issued to the sellers in the CDM acquisition and the 4,701,034 common units to be issued upon conversion of Class E units we issued to the sellers in the FrontStreet acquisition.

Substantially all of the common units so registered remain unsold pursuant to these registration statements. If investors holding these units were to dispose of a substantial portion of these units in the public market, whether in a single transaction or series of transactions, it could temporarily reduce the market price of our outstanding common units. In addition, these sales, or the possibility that these sales may occur, could make it more difficult for us to sell our common units in the future.

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. As of February 7, 2008, our General Partner owns 31.2 percent of the total of our common and subordinated 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 or local entities. If the IRS treats us as a corporation or we become subject to a material amount of entity-level taxation for state or local 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 will 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 and local income tax at varying rates. Distributions to you would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to you would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of the units.

Table of Contents

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. At the federal level, legislation has been proposed that would eliminate partnership tax treatment for certain publicly traded partnerships. Although such legislation would not apply to us as currently proposed, it could be amended prior to enactment in a manner that does apply to us. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units. At the state level, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are required to pay a Texas margin tax. Imposition of such a tax on us by Texas, and, if applicable, by any other state, will reduce our cash available for distribution to you.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be reduced to reflect the impact of that law on us.

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

Table of Contents

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations, and, accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to challenge this method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of the loaned units, he may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our current valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our intangible assets and a lesser portion allocated to our tangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

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

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50 percent or more of the total interests in our capital and profits within a twelve-month period. Pursuant to the GE EFS Acquisition, GE EFS acquired (i) a 37.3 percent limited partner interest in us, (ii) the 2 percent general partner interest in us, and (iii) the right to receive the incentive distributions associated with the general partner interest. We believe, and will take the position, that the GE EFS Acquisition, together with all other common units sold within the prior twelve-month period, represented a sale or exchange of 50 percent or more of the total interest in our capital and profits interests. This termination, among other things, resulted in the closing of our taxable year for all unitholders on June 18, 2007. Such a closing of the books resulted in a significant deferral of depreciation deductions allowable in computing our taxable income. Although our termination likely caused our unitholders to realize an increased amount of taxable income as a percentage of the cash distributed to them in 2007, we anticipate that the ratio of taxable income to distributions for future years will return to levels commensurate with our prior tax periods. However, any future termination of our partnership could have similar consequences. Additionally, in the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. The position that there was a partnership termination does not affect our classification as a partnership for federal income tax purposes; however, we are treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to prevail that a termination occurred.

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, West Virginia and Arkansas. 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 margin tax on corporations and limited liability companies. As we make acquisitions or expand our business, we may own assets or do business in additional states that impose a personal income tax. It is your responsibility to file all United States federal, foreign, state and local tax returns required as a result of being a unitholder.

Table of Contents

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Substantially all of our pipelines, which are located in Texas, Louisiana, Oklahoma, and Kansas 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. Obligations under our credit facility are secured by substantially all of our assets and are guaranteed, except for those owned by one of our subsidiaries, by the Partnership and each such subsidiary. 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.

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. Currently, we are evaluating our executive office space needs. We also maintain small regional offices located on leased premises in Shreveport, Louisiana; and Midland, Houston, and San Antonio, Texas. We lease the San Antonio office space from BBE, 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

We 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.

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.

Part II

Item 5. Market for Registrant's Common Equity Related Stockholder Matters and Purchase 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 NASDAQ under the symbol “RGNC.” As of February 13, 2008, the number of holders of record of common units was 51, including Cede & Co., as nominee for Depository Trust Company, which held of record 29,296,713 common units. Additionally, there were 35 unitholders of record of our subordinated units, one unitholder of record for our Class D common units and one unitholder of record for our Class E common units. There is no established public trading market for our subordinated units, our Class D common units or our Class E common units. Currently, our common units are listed on the Nasdaq Global Select Market. The following table sets forth, for the periods indicated, the high and low quarterly sales prices per common unit, as reported on NASDAQ, and the cash distributions declared per common unit.

Table of Contents

	Price Ranges High	Low	Cash Distributions Declared (per unit)
2006			
First Quarter (1)	$ 22.10	$ 19.47	$ 0.2217
Second Quarter	23.00	21.30	0.3500
Third Quarter (2)	24.52	22.24	0.3700
Fourth Quarter (2)	27.20	24.75	0.3700
2007			
First Quarter	28.40	26.11	0.3800
Second Quarter	33.18	24.97	0.3800
Third Quarter	34.32	29.15	0.3900
Fourth Quarter	33.37	28.46	0.4000
2008			
First Quarter (through February 21, 2008)	32.60	29.71	(3)

(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) Excludes 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, are entitled to future cash distributions from the dates of conversion, respectively.

(3) The cash distribution for the first quarter of 2008 will be determined in April 2008.

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. Holders of our Class D common units and our Class E common units are not entitled to participate in distributions.

Available cash generally means, for any quarter ending prior to liquidation of the Partnership, 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	$0.35	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” for further discussion regarding the restrictions on distributions.

Table of Contents

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 August 15, 2006, in connection with the TexStar acquisition, we issued 5,173,189 of Class B common units to HMTF Gas Partners as partial consideration for the TexStar acquisition. The Class B common units had the same terms and conditions as our common units, except that the Class B common units were 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.

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 had the same terms and conditions as the Partnership's common units, except that the Class C common units were 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.

On April 2, 2007, in connection with the Pueblo Acquisition, we issued 751,597 common units to Bear Cub Investments, LLC and the members of that company as partial consideration for the Pueblo Acquisition. The registrant claims exemption from the registration provisions of the Securities Act of 1933 under section 4(2) thereof for these issuances.

On January 7, 2008, we issued 4,701,034 of Class E common units as partial consideration for the contribution of ASC's 95 percent ownership interest in FrontStreet. The Class E common units had the same terms and conditions as our common units, except that the Class E common units were not entitled to participate in distributions by the Partnership. The Class E common units may be converted into an equivalent number of common units anytime from and after February 15, 2008. The registrant claims exemption from the registration provisions of the Securities Act of 1933 under section 4(2) thereof for these issuances.

On January 15, 2008, we issued 7,276,506 of Class D common units to CDM OLP GP, LLC, the sole general partner of CDM, and CDMR Holdings, LLC, the sole limited partner of CDM, as partial consideration for the CDM Acquisition. The Class D common units have the same terms and conditions as our common units, except that the Class D common units are not entitled to participate in distributions by the Partnership until converted to common units on a one-for-one basis on the close of business on the first business day after the record date for the quarterly distribution on the common units for the quarter ending December 31, 2008. 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.

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, 2007, 2006, 2005, and 2004 and for the years ended December 31, 2007, 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. See "Item 7 — Management's Discussions and Analysis of Financial Condition and Results of Operations — History of the Partnership and its Predecessor" 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.

Table of Contents

	Regency Energy Partners LP				Regency LLC Predecessor	
	Year Ended December 31, 2007	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	$ 1,168,054	$ 896,865	$ 709,401	$ 47,857	$ 432,321	$ 186,533
Total operating expense	1,114,843	857,005	695,366	45,112	404,251	178,172
Operating income	53,211	39,860	14,035	2,745	28,070	8,361
Other income and deductions						
Interest expense, net	(52,016)	(37,182)	(17,880)	(1,335)	(5,097)	(2,392)
Loss on debt refinancing	(21,200)	(10,761)	(8,480)	-	(3,022)	-
Other income and deductions, net	1,308	839	733	64	186	205
Net income (loss) from continuing operations	(18,697)	(7,244)	(11,592)	1,474	20,137	6,174
Discontinued operations	-	-	732	-	(121)	-
Income tax expense	931	-	-	-	-	-
Net income (loss)	$ (19,628)	$ (7,244)	$ (10,860)	$ 1,474	$ 20,016	$ 6,174
Less:						
Net income through January 31, 2006	-	1,564				
Net loss for partners	$ (19,628)	$ (8,808)				
General partner interest	(393)	(176)				
Beneficial conversion feature for Class C common units	1,385	3,587				
Limited partner interest	$ (20,620)	$ (12,219)				
Basic and diluted net loss per common and subordinated unit (1)	$ (0.40)	$ (0.30)				
Cash distributions declared per common and subordinated unit	1.52	0.9417				
Basic and diluted net loss per Class B common unit (1)	-	(0.17)				
Cash distributions declared per Class B common unit	-	-				
Income per Class C common unit due to beneficial conversion feature (1)	0.48	1.26				

Cash distributions declared per Class C common unit	-	-				
Balance Sheet Data (at period end):						
Property, plant and equipment, net	$ 818,054	$ 734,034	$ 609,157	$ 328,784		$ 118,986
Total assets	1,173,877	1,013,085	806,740	492,170		164,330
Long-term debt (long-term portion only)	481,500	664,700	428,250	248,000		55,387
Net equity	470,331	212,657	230,962	181,936		59,856
Cash Flow Data:						
Net cash flows provided by (used in):						
Operating activities	$ 74,413	$ 44,156	$ 37,340	$ (4,311)	$ 32,401	$ 6,494
Investing activities	(151,451)	(223,650)	(279,963)	(130,478)	(84,721)	(123,165)
Financing activities	95,721	184,947	242,949	132,515	56,380	118,245
Other Financial Data:						
Total segment margin (2)	$ 191,909	$ 156,419	$ 76,536	$ 6,870	$ 69,559	$ 23,072
EBITDA (2)	85,058	69,592	30,191	4,470	35,242	12,890
Maintenance capital expenditures	7,734	16,433	9,158	358	5,548	1,633
Segment Financial and Operating Data:						
Gathering and Processing Segment:						
Financial data:						
Segment margin	$ 132,577	$ 111,372	$ 60,864	$ 6,262	$ 61,347	$ 18,805
Operating expenses	40,970	35,008	22,362	1,655	16,230	6,131
Operating data:						
Natural gas throughput (MMbtu/d)	745,020	529,467	345,398	314,812	303,345	211,474
NGL gross production (Bbls/d)	21,803	18,587	14,883	16,321	14,487	9,434
Transportation Segment:						
Financial data:						
Segment margin	$ 59,332	$ 45,047	$ 15,672	$ 608	$ 8,212	$ 4,267
Operating expenses	4,504	4,488	1,929	164	1,556	881
Operating data:						
Throughput (MMbtu/d)	751,761	587,098	258,194	161,584	192,236	211,569

(1) The year ended December 31, 2006 amounts have been corrected for an error made in the calculation of loss per unit resulting from the issuance of Class C common units at a discount.
(2) See "-- Non-GAAP Financial Measures" for a reconciliation to its most directly comparable GAAP measure.

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.

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.

32

Table of Contents

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 expense 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 expenses. 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 expenses from total revenues in calculating total segment margin because we separately evaluate commodity volume and price changes in total segment margin. As an indicator of our operating performance, total segment margin should not be considered an alternative to, or more meaningful than, net income as determined in accordance with GAAP. Our total segment margin may not be comparable to a similarly titled measure of another company because other entities may not calculate total segment margin in the same manner.

	Regency Energy Partners LP				Regency LLC Predecessor	
	Year Ended December 31, 2007	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	$ 74,413	$ 44,156	$ 37,340	$ (4,311)	$ 32,401	$ 6,494
Add (deduct):						
Depreciation and amortization	(53,734)	(39,287)	(24,286)	(1,793)	(10,461)	(4,658)
Write-off of debt issuance costs	(5,078)	(10,761)	(8,480)	-	(3,022)	-
Equity income	43	532	312	56	-	-
Risk management portfolio value changes	(14,667)	2,262	(11,191)	322	-	-
Loss (gain) on assets sales	(1,522)	-	1,254	-	-	-
	(15,534)	(2,906)	-	-	-	-

Unit based compensation expenses						
Accrued revenues and accounts receivable	30,608	5,506	43,012	(2,568)	19,832	31,966
Other current assets	1,293	(104)	2,644	2,456	1,169	1,070
Accounts payable, accrued cost of gas and liquids and accrued liabilities	(36,319)	1,359	(52,651)	(548)	(18,122)	(26,880)
Accrued taxes payable	(835)	(492)	(806)	921	(1,475)	(906)
Other current liabilities	984	(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	1,078	3,862	-	-	-	-
Other assets and liabilities	(358)	(3,283)	3,261	6,697	196	5
Net (loss) income	$ (19,628)	$ (7,244)	$ (10,860)	$ 1,474	$ 20,016	$ 6,174
Add:						
Interest expense, net	52,016	37,182	17,880	1,335	5,097	2,392
Depreciation and amortization	51,739	39,654	23,171	1,661	10,129	4,324
Income tax expense	931	-	-	-	-	-
EBITDA	$ 85,058	$ 69,592	$ 30,191	$ 4,470	$ 35,242	$ 12,890
Reconciliation of "total segment margin" to net (loss) income						
Net (loss) income	$ (19,628)	$ (7,244)	$ (10,860)	$ 1,474	$ 20,016	$ 6,174
Add (deduct):						
Operation and maintenance	45,474	39,496	24,291	1,819	17,786	7,012
General and administrative	39,543	22,826	15,039	645	6,571	2,651
Loss on assets sales, net	1,522	-	-	-	-	-
Management services termination fee	-	12,542	-	-	-	-
Transaction expenses	420	2,041	-	-	7,003	724
Depreciation and amortization	51,739	39,654	23,171	1,661	10,129	4,324
Interest expense, net	52,016	37,182	17,880	1,335	5,097	2,392
Loss on debt refinancing	21,200	10,761	8,480	-	3,022	-
Other income and deductions, net	(1,308)	(839)	(733)	(64)	(186)	(205)
Discontinued operations	-	-	(732)	-	121	-
Income tax expense	931	-	-	-	-	-
Total segment margin	$ 191,909	$ 156,419	$ 76,536	$ 6,870	$ 69,559	$ 23,072

Table of Contents

Item 7. Management's Discussion and Analysis of Financial Condition 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 growth-oriented publicly-traded Delaware limited partnership engaged in the gathering, processing, contract compression, marketing and transportation of natural gas and NGLs. We provide these services through systems located in Louisiana, Texas, Arkansas, and the mid-continent region of the United States, which includes Kansas, Oklahoma, and Colorado.

OUR OPERATIONS. Prior to the acquisition of CDM in January 2008, we managed our business and analyzed and reported our results of operations through two business segments.

§ Gathering and Processing: 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 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: We deliver natural gas from northwest Louisiana to more favorable markets in northeast Louisiana through our 320-mile Regency Intrastate Pipeline system.

On January 15, 2008, we acquired CDM, which now comprises our contract compression segment. Our contract compression segment provides customers with turn-key natural gas compression services to maximize their natural gas and crude oil production, throughput, and cash flow. Our integrated solutions include a comprehensive assessment of a customer's natural gas contract compression needs and the design and installation of a compression system that addresses those particular needs. We are responsible for the installation and ongoing operation, service, and repair of our compression units, which we modify as necessary to adapt to our customers' changing operating conditions.

Through December 31, 2007, all of our revenue is derived from, and all of our assets and operations are part of our gathering and processing segment and our transportation segment. As such the following discussion of our financial condition and results of operation does not reflect our contract compression segment.

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. The following is a summary of our most common contractual arrangements:

§ 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 processing in unfavorable price environments.

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. For example, we seek to replace our longer term keep-whole arrangements as they expire or whenever the opportunity presents itself.

Another way we minimize our exposure to commodity price fluctuations is by executing swap contracts settled against ethane, propane, butane, natural gasoline, crude oil, and natural gas market prices. We continually monitor our hedging and contract portfolio and expect to continue to adjust our hedge position as conditions warrant.

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. 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.

Table of Contents

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.

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.

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 tools for evaluating the success of our operations 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 throughput 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 gathering and processing systems, (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 throughput 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, including 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 of natural gas.

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 the margin generated by 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 measures, net cash flows provided by (used in) operating activities and net income (loss).

Operation and Maintenance Expenses. Operation and maintenance expense 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 expense. 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 expenses 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 partner;
§ 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).

Table of Contents

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 liquefied 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.

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. 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.

HISTORY OF THE PARTNERSHIP AND ITS PREDECESSOR

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 and Duke Energy Field Services Assets. In June 2003, Regency Gas Services LLC acquired certain natural gas gathering, processing, and transportation assets located in north Louisiana and the mid-continent region of the United States from subsidiaries of El Paso Corporation for $119,541,000. In March 2004, Regency Gas Services LLC acquired certain natural gas gathering and processing assets located in west Texas from Duke Energy Field Services, LP for $67,264,000, including transactional costs. Prior to our acquisitions, these assets were operated as components of the seller’s much larger midstream operations. There were no material financial results for periods prior to June 2003.

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. This push down accounting increased deprecation, amortization and interest expenses for periods 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.

Enbridge Asset Acquisition. TexStar acquired two sulfur recovery plants, one NGL plant and 758 miles of pipelines in east and south Texas from subsidiaries of Enbridge for $108,282,000 inclusive of transaction expenses on December 7, 2005. 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.

Acquisition of TexStar. 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.

Pueblo Acquisition. On April 2, 2007, we acquired a 75 MMcf/d gas processing and treating facility, 33 miles of gathering pipelines and approximately 6,000 horsepower of compression. The purchase price for the Pueblo acquisition consisted of (1) the issuance of 751,597 common units, valued at $19,724,000 and (2) the payment of $34,855,000 in cash, exclusive of outstanding Pueblo liabilities of $9,822,000 and certain working capital amounts acquired of $108,000. The Pueblo acquisition was accounted for using the purchase method of accounting. The results of operations of the Pueblo assets are included in our statements of operations beginning April 1, 2007.

GE EFS acquisition of HM Capital's Interest. On June 18, 2007, Regency GP Acquirer LP, an indirect subsidiary of GECC, acquired 91.3 percent of both the member interest in the General Partner and the outstanding limited partner interests in the General Partner from an affiliate of HM Capital Partners. Concurrently, Regency LP Acquirer LP, another indirect subsidiary of GECC, acquired 17,763,809 of the outstanding subordinated units, exclusive of 1,222,717 subordinated units which were owned directly or indirectly by certain members of the Partnership's management team. As a part of this acquisition, affiliates of HM Capital Partners entered into an agreement to hold 4,692,417 of the Partnership's common units for a period of 180 days. In addition, a separate affiliate of HM Capital Partners entered into an agreement to hold 3,406,099 of the Partnership's common units for a period of one year.

GE Energy Financial Services is a unit of GECC which is an indirect wholly owned subsidiary of GE. For simplicity, we refer to Regency GP Acquirer LP, Regency LP Acquirer LP and GE Energy Financial Services collectively as "GE EFS." Concurrent with the Partnership's issuance of common units in July and August 2007, GE EFS and certain members of the Partnership's management made a capital contribution aggregating to $7,735,000 to maintain the General Partner's two percent interest in the Partnership.

Concurrent with the GE EFS acquisition, eight members of the Partnership's senior management, together with two independent directors, entered into an agreement to sell an aggregate of 1,344,551 subordinated units to for a total consideration of $24.00 per unit. Additionally, GE EFS entered into a subscription agreement with four officers and certain other management of the Partnership whereby these individuals acquired an 8.2 percent indirect economic interest in the General Partner.

The Partnership was not required to record any adjustments to reflect GE EFS's acquisition of the HM Capital Partners' interest in the Partnership or the related transactions (together, referred to as "GE EFS Acquisition").

Table of Contents

RESULTS OF OPERATIONS

Year Ended December 31, 2007 vs. Year Ended December 31, 2006

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

	Year Ended December 31, 2007	2006	Change	Percent
	(in thousands)			
Total revenues	$ 1,168,054	$ 896,865	$ 271,189	30%
Cost of gas and liquids	976,145	740,446	235,699	32
Total segment margin (1)	191,909	156,419	35,490	23
Operation and maintenance	45,474	39,496	5,978	15
General and administrative (2)	39,543	22,826	16,717	73
Loss on asset sales, net	1,522	-	1,522	n/m
Management services termination fee	-	12,542	(12,542)	(100)
Transaction expenses	420	2,041	(1,621)	(79)
Depreciation and amortization	51,739	39,654	12,085	30
Operating income	53,211	39,860	13,351	33
Interest expense, net	(52,016)	(37,182)	(14,834)	(40)
Loss on debt refinancing	(21,200)	(10,761)	(10,439)	(97)
Other income and deductions, net	1,308	839	469	56
Loss before income taxes	(18,697)	(7,244)	(11,453)	158
Income tax expense	931	-	931	n/m
Net loss	$ (19,628)	$ (7,244)	$ (12,384)	171
System inlet volumes (MMBtu/d) (3)	1,198,008	1,010,642	187,366	19%

(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) Includes a one-time charge of $11,928,000 related to our long-term incentive plan associated with the vesting of all outstanding common units options and restricted common units on June 18, 2007 with the change in control from HM Capital to GE EFS.

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

n/m = not meaningful

Table of Contents

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

	Year Ended December 31, 2007	2006	Change	Percent
	(in thousands)			
Gathering and Processing Segment				
Financial data:				
Segment margin (1)	$ 132,577	$ 111,372	$ 21,205	19%
Operation and maintenance	40,970	35,008	5,962	17
Operating data:				
Throughput (MMBtu/d)	745,020	529,467	215,553	41
NGL gross production (Bbls/d)	21,803	18,587	3,216	17
Transportation Segment				
Financial data:				
Segment margin (1)	$ 59,332	$ 45,047	$ 14,285	32%
Operation and maintenance	4,504	4,488	16	0
Operating data:				
Throughput (MMBtu/d)	751,761	587,098	164,663	28

(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, 2007 increased $12,384,000 compared with the year ended December 31, 2006. An increase in total segment margin of $35,490,000, primarily due to organic growth in the gathering and processing segment; the absence in 2007 of management services termination fees of $12,542,000 from our initial public offering and TexStar acquisition; and a decrease in transaction expenses of $1,621,000 associated with acquisitions of entities under common control were more than offset by:

§ an increase in general and administrative expense of $16,717,000 primarily due to a one-time charge of $11,928,000 related to our long-term incentive plan associated with the vesting of all outstanding common unit options and restricted common units on June 18, 2007 with the change in control from HM Capital to GE EFS and higher employee related expenses;
§ an increase in interest expense, net of $14,834,000 primarily due to increased levels of borrowings used primarily to finance our Pueblo acquisition and growth capital projects;
§ an increase in loss on debt refinancing of $10,439,000 primarily due to a $16,122,000 early termination penalty in 2007 associated with the redemption of 35 percent of our senior notes partially offset by a $5,683,000 decrease in the write-off of capitalized debt issuance costs related to paying off or refinancing credit facilities;
§ an increase in depreciation and amortization of $12,085,000 primarily due to higher levels of depreciation from projects completed since December 31, 2006 and our Pueblo acquisition;
§ an increase in operation and maintenance expense of $5,978,000 primarily due to increased employee related expenses, increased consumables expense, increased contractor expense and other factors discussed below; and
§ a net loss on the sale of certain non-core assets of $1,522,000 in the year ended December 31, 2007.

Segment Margin. Total segment margin for the year ended December 31, 2007 increased $35,490,000 compared with the year ended December 31, 2006. This increase was attributable to an increase of $21,205,000 in gathering and processing segment margin and an increase of $14,285,000 in transportation segment margin as discussed below.

Gathering and processing segment margin increased to $132,577,000 for the year ended December 31, 2007 from $111,372,000 for the year ended December 31, 2006. The major components of this increase were as follows:

- § $23,233,000 attributable to organic growth projects in the east and south Texas regions;
- § $15,538,000 attributable to organic growth in the north Louisiana region; and offset by
- § $17,449,000 of non-cash losses from certain risk management activities.

Transportation segment margin increased to $59,332,000 for the year ended December 31, 2007 from $45,047,000 for the year ended December 31, 2006. The major components of this increase were as follows:

- § $11,512,000 attributable to increased throughput volumes;
- § $1,752,000 of increased margins related to our merchant function;
- § $631,000 attributable to increased margins per unit of throughput; and
- § $390,000 of non-cash gains from certain risk management activities.

Table of Contents

Operation and Maintenance. Operations and maintenance expense increased to $45,474,000 in the year ended December 31, 2007 from $39,496,000 for the corresponding period in 2006, a 15 percent increase. This increase is primarily the result of the following factors:

- $3,217,000 of increased employee related expenses primarily in the gathering and processing segment resulting from additional employees related to organic growth and employee annual pay raises;
- $1,335,000 of increased materials and parts expense primarily in the gathering and processing segment used at our processing plants and for additional compression;
- $1,219,000 of increased consumable expenses primarily in the gathering and processing segment largely resulting from additional compression;
- $1,034,000 of increased contractor expense primarily in the gathering and processing segment associated with our Fashing processing plant;
- $811,000 of increased utility expense primarily in the gathering and processing segment resulting from one of our north Louisiana refrigeration plants placed in service in December 2006; and
- $637,000 of unplanned outage expense in the transportation segment in 2007 related to the Eastside compressor fire, which represents our estimated thirty day deductible.

Partially offsetting these increases in operation and maintenance expense were the following factors:

- $1,741,000 of insurance proceeds associated with our unplanned compressor outage in the transportation segment in 2007; and
- $549,000 of decreased rental expense primarily in the gathering and processing segment from fewer leased compressor units.

General and Administrative. General and administrative expense increased to $39,543,000 in the year ended December 31, 2007 from $22,826,000 for the same period in 2006, a 73 percent increase. The increase is primarily due to:

- a one-time charge of $11,928,000 related to our long-term incentive plan associated with the vesting of all outstanding common unit options and restricted common units on June 18, 2007 with the change in control from HM Capital to GE EFS;
- $3,607,000 of increased employee related expenses resulting from pay raises and the hiring of additional employees;
- $777,000 of increased professional and consulting expense primarily for Sarbanes-Oxley compliance;
- $700,000 of increased expenses associated with our long-term incentive plan that primarily relates to the issuance of restricted units, exclusive of the one-time charge discussed above; and
- partially offsetting these increases was the absence in 2007 of management fees of $361,000 in 2006.

Other. In the year ended December 31, 2006, we recorded charges of $12,542,000 for the termination of long-term management services contracts in connection with our initial public offering and TexStar acquisition. In the years ended December 31, 2007 and December 31, 2006, we incurred transaction expenses of $420,000 related to our 2008 FrontStreet acquisition and $2,041,000 related to our TexStar acquisition. Since these acquisitions involve entities under common control, we accounted for these transactions in a manner similar to pooling of interests and expensed the transaction costs. In the year ended December 31, 2007, we sold certain non-core assets and recorded a related net charge of $1,522,000.

Depreciation and Amortization. Depreciation and amortization expense increased to $51,739,000 in the year ended December 31, 2007 from $39,654,000 for the year ended December 31, 2006, a 30 percent increase. The increase is due to higher depreciation expense of $10,579,000 primarily from projects completed since December 31, 2006 and our Pueblo acquisition. Also contributing to the increase was higher identifiable intangible asset amortization of $1,506,000 primarily related to contracts associated with the Pueblo acquisition and the TexStar acquisition in April 2007 and July 2006, respectively.

Interest Expense, Net. Interest expense, net increased $14,834,000, or 40 percent, in the year ended December 31, 2007 compared to the same period in 2006. Of this increase, $8,243,000 was attributable to increased levels of borrowings and $4,026,000, was attributable to higher interest rates partially offset by the 2006 reclassification of $2,607,000 from accumulated other comprehensive income associated with the gain upon the termination of an interest rate swap.

Loss on Debt Refinancing. In the year ended December 31, 2007, we paid a $16,122,000 early repayment penalty associated with the redemption of 35 percent of our senior notes. We also expensed $5,078,000 of debt issuance costs related to the pay off of the term loan facility and the early termination of senior notes. In the year ended December 31, 2006, we wrote-off $5,626,000 of debt issuance costs to amend and restate our credit facility and we wrote-off $5,135,000 of debt issuance costs associated with paying off TexStar’s loan agreement as part of our TexStar acquisition.

Table of Contents

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	740,446	632,865	107,581	17
Total segment margin (1)	156,419	76,536	79,883	104
Operation and maintenance	39,496	24,291	15,205	63
General and administrative	22,826	15,039	7,787	52
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
Loss on debt refinancing	(10,761)	(8,480)	(2,281)	27
Other income and deductions, net	839	733	106	14
Loss from continuing operations	(7,244)	(11,592)	4,348	38
Discontinued operations	-	732	(732)	(100)
Net loss	$ (7,244)	$ (10,860)	$ 3,616	(33)%
System inlet volumes (MMBtu/d)(2)	1,010,642	603,592	407,050	67%

(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.

	Year Ended December 31, 2006	2005	Change	Percent
	(in thousands)			
Gathering and Processing Segment				
Financial data:				
Segment margin (1)	$ 111,372	$ 60,864	$ 50,508	83%
Operation and maintenance	35,008	22,362	12,646	57
Operating data:				
Throughput (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:				
Throughput (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".

Table of Contents

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 $79,883,000 largely 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:

§ interest expense, net increased $19,302,000 primarily due to increased levels of borrowing to fund acquisitions and capital expenditures;
§ 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;
§ operation and maintenance increased $15,205,000 primarily due to a full year of expense in 2006 for the TexStar;
§ management service termination fees of $12,542,000 in 2006, which were not present in 2005;
§ 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;
§ 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
§ 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 $156,419,000 from $76,536,000 for the year ended December 31, 2005, representing a 104 percent increase.

Gathering and Processing segment margin for the year ended December 31, 2006 increased to $111,372,000 from $60,864,000 for the year ended December 31, 2005, representing an 83 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
§ $2,109,000 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 the enhancement of our RIGS pipeline.

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

Table of Contents

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.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

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 maintenance and growth capital expenditures for the next twelve months.

See "— History of the Partnership and its Predecessor" 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 increased by $5,925,000 from December 31, 2006 to December 31, 2007 primarily due to the following:

§ a $36,331,000 decrease in working capital due to an increase in net current liabilities from risk management activities resulting from an increase in the commodity prices we expect to pay (index prices) on our outstanding swaps as compared to the commodity prices we expect to receive upon settlement;
§ an $18,683,000 increase in working capital resulting from an increase in cash and cash equivalents primarily due to the timing of payment of accounts payable; and
§ a $10,772,000 increase in working capital resulting from an increase in net accounts receivable and payable due to the timing of cash receipts and payments.

Cash Flows from Operating Activities. Net cash flows provided by operating activities increased $30,257,000, or 69 percent, for the year ended December 31, 2007 as compared to the year ended December 31, 2006. Cash generated from operations increased primarily due to increased total segment margin of $35,490,000, primarily due to organic growth in the gathering and processing segment.

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 resulting from the completion of the enhancement of our RIGS pipeline, 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 because 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.

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, 2007 and 2006 were $178,930,000 and $112,600,000, respectively.

Table of Contents

Cash Flows from Investing Activities. Net cash flows used in investing activities decreased $72,199,000, or 32 percent, in the year ended December 31, 2007 compared to the year ended December 31, 2006. The decrease is primarily due to our 2006 Como assets acquisition ($81,695,000), proceeds from the asset sales in 2007 of $11,706,000, a decrease in spending on growth and maintenance capital expenditures of $19,121,000, partially offset by our 2007 Pueblo acquisition ($34,855,000).

Growth Capital Expenditures. In the year ended December 31, 2007, we incurred $78,305,000 of growth capital expenditures. Growth capital expenditures for the year ended December 31, 2007 primarily relate to the following projects:

§ $8,300,000 for constructing 20 miles of 10 inch diameter pipeline, which will connect the Fashing Processing Plant to our Tilden Processing Plant in south Texas and reconfiguring our Tilden Processing Plant, expected to be completed in the first half of 2008;
§ $11,500,000 to re-build and activate an existing nitrogen rejection unit at our Eustace Processing Plant, completed in the second quarter of 2007;
§ $8,600,000 for constructing 31 miles of 12 inch diameter pipeline in south Texas, completed in the second quarter of 2007; and
§ $8,100,000 for the electrification and adding an acid gas injection well at our Tilden Processing Plant, completed in the second quarter of 2007.

Our 2008 growth budget includes $208,000,000 of currently identified organic growth capital expenditures, including $118,000,000 for CDM compression for an additional 174,700 horsepower. The significant growth capital expenditures in our gathering and processing segment are for the following projects:

§ $14,300,000, in addition to the $8.300,000 spent in 2007, for constructing 20 miles of 10 inch diameter pipeline, which will connect the Fashing Processing Plant to our Tilden Processing Plant in south Texas and reconfiguring our Tilden Processing Plant, expected to be completed in the first half of 2008;
§ $16,700,000 for constructing a 40 mile, 10 inch diameter pipeline, expected to be completed in 2008;
§ $9,394,000 for construction and equipment related to a joint venture in south Texas;
§ $6,700,000 for compression and gathering in south Texas; and
§ $5,800,000 for Dubach plant expansion.

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 proceeds from the issuance and sale of debt and equity securities to finance any future growth capital expenditures or acquisitions.

Maintenance Capital Expenditures. In the year ended December 31, 2007, we incurred $7,734,000 of maintenance capital expenditures. 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 2008 budget for maintenance capital expenditures is $17,000,000.

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 below. We categorize our capital expenditures as either: (a) 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 (b) maintenance capital expenditures, which are made 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.

Cash Flows from Financing Activities. Net cash flows provided by financing activities decreased $89,226,000, or 48 percent, in the year ended December 31, 2007 compared to the year ended December 31, 2006 primarily due to the following:

§ a decrease in borrowings under our credit facility of $599,650,000 due to restructuring our capitalization;

§ an increase in partner distributions of $42,789,000 due to increased distributions per unit and an increase in the number of partner units receiving distributions, no partner distributions paid in the quarter ended March 31, 2006 and a partial partner distribution paid in the quarter ended June 30, 2006 resulting from the timing of our initial public offering;

§ an increase in proceeds from equity issuances of $40,846,000 due to the issuance in 2007 of 11,500,000 common units for $353,546,000, net of issuance costs, the proceeds of which were used to repay 35 percent or $192,500,000 of our senior notes, to repay our $50,000,000 term loan, and to pay down our revolving credit facility. In 2006 we issued 13,750,000 common units in our initial public offering and 2,857,143 Class C common units for $312,700,000, net of issuance costs.

Table of Contents

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:

- § $42,975,000 net borrowings under our credit facility to finance our TexStar acquisition, organic growth projects, working capital requirements and the costs to amend and restate our credit facility;
- § $37,144,000 of partner distributions made in 2006 not made in 2005; and
- § 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.

Capital Resources

Description of Our Indebtedness. As of December 31, 2007, our aggregate outstanding indebtedness totaled $481,500,000 and comprised of $124,000,000 in borrowings under our revolving credit facility and $357,500,000 of outstanding senior notes, respectively, as compared to our aggregate outstanding indebtedness as of December 31, 2006, which totaled $664,700,000 and comprised of $114,700,000 in borrowings under our revolving credit facility and $550,000,000 of outstanding senior notes.

Credit Ratings. Moody's Investors Service has assigned a Corporate Family Rating to us of Ba3, a B1 rating for our senior notes and a Speculative Grade Liquidity rating of SGL-3. Standard & Poor's Ratings Services has assigned a Corporate Credit Rating of BB- and a B rating for our senior notes.

Fourth Amended and Restated Credit Agreement. We have a $900,000,000 revolving credit facility. The availability for letters of credit is $100,000,000. We have the option to request an additional $250,000,000 in revolving commitments with 10 business days written notice 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.

Obligations under the credit facility are secured by substantially all of our assets and are guaranteed, except for those owned by one of our subsidiaries, by the Partnership and each such subsidiary. The revolving loans mature in five years. Interest on revolving loans thereunder will be calculated, at the our option, at either: (a) a base rate plus an applicable margin of 0.50 percent per annum or (b) an adjusted LIBOR rate plus an applicable margin of 1.50 percent per annum. The weighted average interest rate for the revolving and term loan facilities, including interest rate swap settlements, commitment fees, and amortization of debt issuance costs was 8.78 percent for the year ended December 31, 2007. We must pay (i) a commitment fee equal to 0.30 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 1.50 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 us to maintain the ratios of debt to consolidated EBITDA and consolidated EBITDA to interest expense within certain threshold ratios. The credit facility restricts the ability of RGS to pay dividends and distributions other than reimbursement of the Partnership for expenses and payment of distributions to the Partnership to the extent of our determination of available cash as defined in our partnership agreement (so long as no default or event of default has occurred or is continuing). The credit facility also contains certain other covenants.

Letters of Credit. At December 31, 2007, we had outstanding letters of credit totaling $27,263,000. The total fees for letters of credit accrue at an annual rate of 1.5 percent, which is applied to the daily amount of letters of credit exposure.

Senior Notes. In 2006, the Partnership and Regency Energy Finance Corp., a wholly owned subsidiary of RGS, issued, in a private placement, $550,000,000 in principal amount of senior notes that mature on December 15, 2013 ("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, and are guaranteed by all of our subsidiaries. In August 2007, we redeemed 35 percent, or $192,500,000, of the aggregate principal amount of the senior notes with the net cash proceeds from our July 2007 equity offering and we paid an early redemption penalty of $16,122,000. In September 2007, the Partnership exchanged its then outstanding 8 3/8 percent senior notes which were not registered under the Securities Act of 1933 for senior notes with identical terms that have been so registered

The senior notes and the guarantees are unsecured and rank equally with all of our and the guarantors' existing and future unsubordinated obligations. The senior notes and the guarantees are 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 are effectively subordinated to our and the guarantors' secured obligations, including our credit facility.

The senior 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. No guarantor may 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; 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.

Table of Contents

Upon a change of control, each holder of senior 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. At December 31, 2007, we were in compliance with these covenants.

Equity Offering. In July 2007, the Partnership sold 10,000,000 common units for $32.05 per unit. After deducting underwriting discounts and commissions of $12,820,000, the Partnership received $307,680,000 from this sale, excluding the general partner's proportionate capital contribution of $6,279,000 and offering expenses to date of $386,000. On July 31, 2007, the Partnership sold an additional 1,500,000 common units for $32.05 per unit upon exercise by the underwriters of their option to purchase additional units. The Partnership received $46,152,000 from this sale after deducting underwriting discounts and commissions and excluding the general partner's proportionate capital contribution of $942,000.

The Partnership used a portion of these proceeds to repay amounts outstanding under the term ($50,000,000) and revolving credit facility ($178,930,000). With the remaining proceeds and additional borrowings under the revolving credit facility, the Partnership redeemed $192,500,000, or 35 percent of its outstanding senior notes, an event which required the Partnership to pay an early redemption penalty of $16,122,000 in August 2007.

Universal Shelf. We have filed with the SEC a universal shelf registration statement that, subject to agreement on terms at the time of use and appropriate supplementation, allows us to issue, in one or more offerings, up to an aggregate of $1,000,000,000 of equity securities, debt securities or a combination thereof. We have remaining $323,747,000 of availability under this shelf registration, subject to customary marketing terms and conditions.

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, 2007.

	Payments Due by Period				
Contractual Cash Obligations	Total	2008	2009-2010	2011-2012	Thereafter
			(in thousands)		
Long-term debt (including interest) (1)	$ 693,821	$ 38,955	$ 77,910	$ 189,515	$ 387,441
Capital leases	10,093	402	811	870	8,010
Operating leases	1,082	505	390	187	-
Purchase obligations	8,539	8,539	-	-	-
Total (2) (3)	$ 713,535	$ 48,401	$ 79,111	$ 190,572	$ 395,451

(1) Assumes a constant current LIBOR interest rate of 4.86 percent plus the applicable margin on our revolver. The principal ($357,500,000) of our outstanding senior notes bears a fixed interest rate of 8 3/8 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.

(3) Excludes deferred tax liabilities of $8,642,000 as the amount payable by period cannot be reliably estimated considering the future business plans for the entity that generates the deferred tax liability.

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 and results of operations.

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

Table of Contents

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Conformity with GAAP 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. We estimate 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 measured volumes. In the subsequent production month, we reverse the accrual and record the actual results. Prior to the settlement date, we record actual operating data to the extent available, such as actual operating and maintenance and other expenses. We do not expect actual results to differ materially from our estimates.

Risk Management Activities. In order to protect ourselves from commodity price 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. 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 recorded the unrealized changes in fair value in other comprehensive income (loss) to the extent the hedge are effective. Effective June 19, 2007, we elected to account for our entire outstanding commodity hedging instruments on a mark-to-market basis except for the portion of commodity hedging instruments where all NGLs products for a particular year were hedged and the hedging relationship was effective. As a result, a portion of our commodity hedging instruments is and will continue to be accounted for using mark-to-market accounting until all NGLs products are hedged for an individual year and the hedging relationship is deemed effective.

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, Cost Capitalization and Impairment. 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.

We review long-lived assets for impairment whenever events or changes in circumstances indicate that the related carrying amounts may not be recoverable. Determining whether an impairment has occurred typically requires various estimates and assumptions, including determining which undiscounted cash flows are directly related to the potentially impaired asset, the useful life over which cash flows will occur, their amount, and the asset's residual value, if any. In turn, measurement of an impairment loss requires a determination of fair value, which is based on the best information available. We derive the required undiscounted cash flow estimates from our historical experience and our internal business plans. To determine fair value, we use our internal cash flow estimates discounted at an appropriate interest rate, quoted market prices when available and independent appraisals, as appropriate.

Table of Contents

Equity Based Compensation. Awards under our LTIP have been made prior to the GE EFS acquisition generally vested over a three year period on the basis of one-third of the award each year. Options have a maximum contractual term, expiring ten years after the grant date. Options granted were valued using the Black-Scholes option pricing model, using assumptions of volatility in the unit price, a ten year term, a strike price equal to the grant-date price per unit, a distribution per unit at the time of grant, a risk-free rate, 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. There have been no option awards made subsequent to the GE EFS Acquisition.

RECENT ACCOUNTING PRONOUNCEMENTS

See discussion of new accounting pronouncements in Note 2 in the Notes to the Consolidated Financial Statements.

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 General Partner is responsible for delegation of transaction authority levels, and the Risk Management Committee of our General Partner is responsible for the overall management of credit risk and commodity price risk, including monitoring exposure limits. 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 and condensate, and as such our financial results are exposed to fluctuations in NGL pricing. We have executed swap contracts settled against condensate, ethane, propane, butane, and natural gasoline market prices. We have hedged our expected exposure to decline in prices for NGLs and condensate volumes produced for our account in the approximate percentages set for below:

	2008	2009
NGL	85%	32%
Condensate	66	67

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, 2007. 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		We Pay	We Receive		Fair Value Asset/(Liability) (in thousands)	
January 2008 – December 2008	Ethane	740	(MBbls)	Index	$ 0.58-$0.615	($/gallon)	$	(11,155)
January 2008 – December 2009	Propane	813	(MBbls)	Index	$ 0.929-$1.06	($/gallon)		(14,908)
January 2008 – December 2009	Normal Butane	524	(MBbls)	Index	$ 1.119-$1.255	($/gallon)		(10,725)
January 2008 – December 2009	Natural Gasoline	305	(MBbls)	Index	$ 1.409-$1.57	($/gallon)		(5,930)
January 2008 – December 2009	West Texas Intermediate Crude	475	(MBbls)	Index	$ 68.17-$68.38	($/Bbl)		(10,205)
Total							$	(52,923)

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 a parental guarantee.

Table of Contents

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 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, 2007, the letter of credit is $4,800,000 and customer was current in its payment obligations.

Interest Rate Risk. We are exposed to variable interest rate risk as a result of borrowings under our existing credit facility. As of December 31, 2007, we had $124,000,000 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 $1,240,000.

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

On June 18, 2007, Deloitte & Touche LLP ("Deloitte") advised the Partnership that, in light of the change of control from HM Capital to GE EFS and because of existing relationships with GE, effective as of the date of the change of control of the Partnership, Deloitte would no longer be able to serve as the Partnership's independent registered public accounting firm because it would no longer satisfy the independence requirements necessary to certify the financial statements of the Partnership. As a result, Deloitte resigned as the Partnership's independent registered public accounting firm, effective as of June 18, 2007.

Deloitte has expressed an unqualified opinion on the consolidated financial statements of the Partnership for the years ended December 31, 2006 and 2005. Such opinion included an explanatory paragraph related to the Partnership's accounting for its acquisition of TexStar as entities under common control in a manner similar to a pooling of interests. During the two most recent fiscal years and interim period preceding Deloitte's resignation, there were no disagreements with Deloitte and no reportable events as defined under Item 304(a)(1)(v) of Regulation S-K. A copy of Deloitte's letter dated June 18, 2007 is incorporated by reference as Exhibit 16.1.

On June 18, 2007, the board of directors of the General Partner, subject to approval of the engagement terms by the Audit Committee, requested KPMG LLP ("KPMG") to act as the independent registered public accounting firm in auditing the financial statements of the Partnership for the year ending December 31, 2007 and in performing such other attestation services for the Partnership as may be required for the remainder of calendar year 2007. On June 26, 2007, the Audit Committee of the Partnership approved the engagement terms of KPMG and authorized KPMG to serve as the Partnership's independent registered public accountants for the fiscal year ending December 31, 2007.

Item 9A. Controls and Procedures

Evaluation of Disclosure 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. Disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed in the reports we file or submit under the Exchange Act is accumulated and communicated to our management, including the Chief Executive Officer and Chief Financial Officer of our General Partner, as appropriate to allow timely decisions regarding required disclosure.

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 our disclosure control issues have been detected. These inherent limitations include the realities 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.

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 General Partner, of the effectiveness of the design and operation of our disclosure controls and procedures (as such are defined in Rule 13a-15(e) and 15d-15(e) of the Exchange Act). Based on management's evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective in achieving that level of reasonable assurance as of December 31, 2007.

Internal Control over Financial Reporting.
(a) Management's Report on Internal Control over Financial Reporting. Management of our General Partner is responsible for establishing and maintaining adequate internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting for the Partnership as defined in Rules 13a-15(f) as promulgated under the Exchange Act of 1934, as amended.

Table of Contents

Those rules define internal control over financial reporting as a process designed by, or under the supervision of our General Partner's principal executive and principal financial officers and effected by its Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and include those policies and procedures that:

§ Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the Partnership's assets;
§ Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Partnership are being made only in accordance with authorizations of our General Partner's management and directors; and
§ Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Partnership's assets that could have a material effect on the financial statement.

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

Management of our General Partner assessed the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2007. In making this assessment, management used the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO Framework"). The evaluation included an evaluation of the design of the Partnership's internal control over financial reporting and testing of the operating effectiveness of those controls.

Based on its assessment, management has concluded that the Partnership's internal control over financial reporting was effective as of December 31, 2007.

(b) Audit Report of the Registered Public Accounting Firm. KPMG LLP, the independent registered public accounting firm that audited the Partnership's consolidated financial statements included in this report, has issued an audit report on the Partnership's internal control over financial reporting, which report is included herein on page F-3.

(c) Changes in Internal Control over Financial Reporting. As required by Exchange Act Rule 13a-15(f), management of our General Partner, including the Chief Executive Officer and Chief Financial Officer, also conducted an evaluation of the Partnership's internal control over financial reporting to determine whether any change occurred during the last fiscal quarter of the period covered by this report that has materially affected, or is reasonably likely to materially affect, the Partnership's internal control over financial reporting. Based on that evaluation, there has been no change in the Partnership's internal control over financial reporting during the last fiscal quarter of the period covered by this report that has materially affected, or is reasonably likely to materially affect, the Partnership's internal control over financial reporting.

On January 15, 2008, the Partnership acquired CDM. The Partnership initiated the process of integrating CDM to ensure compliance with the internal control and disclosure provisions of the Sarbanes-Oxley Act of 2002. The impact of the acquisition of CDM has not materially affected and is not expected to materially affect the Partnership's internal control over financial reporting. As a result of these integration activities, certain controls will be evaluated and they may be changed. The Partnership believes, however, it will be able to maintain sufficient controls over the substantive results of its financial reporting throughout this integration process.

Item 9B. Other Information

None.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Management. Our General Partner manages and directs all of our activities. Our officers and directors are officers and directors of the General Partner. The owner of the General Partner may appoint up to ten persons to serve on the Board of Directors of the General Partner. Although there is no requirement that he do so, the President and Chief Executive Officer of the General Partner is currently a director of the General Partner and serves as Chairman of the Board of Directors.

Our Board of Directors is currently comprised of its Chairman (the President and Chief Executive Officer of the General Partner), three persons who qualify as "independent" under NASDAQ standards for audit committee members and five persons who were either appointed by the sole member of the General Partner or elected by the other members of the Board of Directors.

Following our notice to NASDAQ of Mr. Robert W. Shower's resignation in February 2007, we received a NASDAQ Staff Deficiency Letter on February 15, 2007 notifying us that we thereby no longer complied with Marketplace rule 4350 relating to the composition of our Audit Committee. Compliance is required for continued listing on NASDAQ, but, in accordance with Marketplace rule 4350(d)(4), the NASDAQ provided a cure period of one year within which to reestablish compliance. Effective January 24, 2008, A. Dean Fuller resigned from the Board of Directors and Michael J. Bradley and John T. Mills were elected as directors of the General Partner. Following a determination by the Board that both directors satisfied the criteria for independence under the Marketplace Rules of NASDAQ, both new directors were appointed to the Audit Committee. The election of the directors brings the Partnership back into compliance with the NASDAQ Rule 4350.

On October 26, 2007, the Board of Directors of the Partnership announced that it had initiated a search for a chief executive officer to replace James W. Hunt, the Partnership's President and Chief Executive Officer, upon his planned retirement in 2008.

Table of Contents

Corporate Governance.   The Board of Directors 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 General Partner. The Corporate Governance Guidelines, the Code of Business Conduct, Code of Conduct of Senior Financial Officers, 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 independent directors as 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 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 or its Board of Directors of any duties they may owe us or the common unitholders. The Conflicts Committee, like the Audit Committee, is composed only of independent directors.

Audit Committee. The Board of Directors has established an Audit Committee in accordance with Exchange Act rules. The Board of Directors appointed three directors who are independent under the NASDAQ's standards for audit committee members to serve on its Audit Committee. In addition, the Board of Directors determined that at least one member, J. Otis Winters, of the Audit Committee has such accounting or related financial management expertise sufficient to qualify such person as the audit committee financial expert in accordance with Item 401 of Regulation S-K.

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 that 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 114 (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 rules to appoint a Compensation Committee or a Nominating/Corporate Governance Committee, as a limited partnership, the Board of Directors of the 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.

The Board of Directors has also appointed a Nominating Committee to assist the Board and the member of our 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. 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 General Partner is required to maintain a sufficient number of independent directors (as defined by the NASDAQ 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. 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.

Table of Contents

Directors and Executive Officers. The following table shows information regarding the current directors and executive officers of the General Partner. Directors are elected for one-year and until their successors are duly elected or until the earlier of their resignation, death or removal.

Name	Age	Position with Regency GP LLC
James W. Hunt(1)(4)(6)	64	Chairman of the Board, President and Chief Executive Officer
Richard D. Moncrief	48	Executive Vice President and Chief Operating Officer
Stephen L. Arata	42	Executive Vice President and Chief Financial Officer
William E. Joor III	68	Executive Vice President, Chief Legal and Administrative Officer and Secretary
Lawrence B. Connors	56	Senior Vice President, Finance and Chief Accounting Officer
George B. Courcier	51	Senior Vice President, Operations
Charles M. Davis, Jr.	45	Senior Vice President, Corporate Development
Shannon A. Ming	31	Vice President, Investor Relations and Communications
James M. Richter	55	Vice President, Human Resources
Houston C. Ross III	37	Vice President, Financial Analysis and Planning
Christofer D. Rozzell	31	Vice President, Corporate Development
A. Troy Sturrock	37	Vice President, Controller
Ramon Suarez, Jr.	45	Vice President, Treasurer
Michael J. Bradley(1)(2)(3)(4)	53	Director
James F. Burgoyne(1)	49	Director
Daniel R. Castagnola(1)(5)(6)	41	Director
Paul J. Halas(4)(6)	51	Director
Mark T. Mellana(4)(5)	43	Director
John T. Mills(2)(3)(5)	60	Director
Brian P. Ward(1)	48	Director
J. Otis Winters(2)(3)	71	Director

(1) Member of the Executive Committee. Mr. Burgoyne is chairman of this committee.
(2) Member of the Audit Committee. Mr. Winters is chairman of this committee.
(3) Member of Conflicts Committee. Mr. Winters is chairman of this committee.
(4) Member of Compensation Committee. Mr. Mellana is chairman of this committee.
(5) Member of Risk Management Committee. Mr. Mellana is chairman of this committee.
(6) Member of Nominating Committee. Mr. Castagnola is chairman of this committee.

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 LP and its predecessor. 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.

Richard D. Moncrief was elected Executive Vice President and Chief Operating Officer of Regency GP LLC in June 2007. From April 2006 to June 2007, Mr. Moncrief served as Senior Vice President of Gas Supply and Business Development of Regency GP LLC. Prior to April 2006, Mr. Moncrief was associated with Sid Richardson Energy Services, of Fort Worth, Texas, where, until that company's sale, he was Vice President, Business Development, and more recently Vice President, Engineering & Business Development. He previously held management positions at Koch Midstream Services Company and at Delhi Gas Pipeline Corporation.

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 LP and its predecessor. 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.

Table of Contents

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 LP and its predecessor. 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.

Lawrence B. Connors was elected Senior Vice President of Finance and Chief Accounting Officer of Regency GP LLC in February 2008, having served as Vice President, Finance and Chief Accounting Officer from 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. Mr. Connors is a Certified Public Accountant.

George B. Courcier was elected Senior Vice President, Operations of Regency GP LLC in February 2008, having served as Vice President, Operations from November, 2007. From October 2005 through November 2007, Mr. Courcier served as Manager of the Midstream Division for Samson Resources. From April 1999 to October 2005, Mr. Courcier served as General Manager of Operations as well as Division Engineering Manager for Duke Energy Field Services. Mr. Courcier has 29 years of experience in the E&P and Midstream sectors of the oil and gas industry.

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.

Shannon A. Ming was elected Vice President, Investor Relations and Communications of Regency GP LLC in February 2008. Mrs. Ming joined Regency GP LLC in April, 2006 as Director of Investor Relations. From August 2001 to March 2006, Mrs. Ming served in various capacities with TXU Corp., including managerial positions in strategic planning, product development and marketing. Mrs. Ming holds a Masters of Business Administrations from Southern Methodist University, where she graduated with honors, and a Masters of Public Health from the University of Texas.

James M. Richter was elected Vice President, Human Resources in June 2007. From January 2007 to the present, Mr. Richter served as the human resources manager at Regency GP LLC. From October 2005 to August 2006, Mr. Richter worked for USAA as Senior People Officer. From June 2001 to August 2005, Mr. Richter was employed by Argonaut Group, Inc. as Vice President, Human Resources. Prior to Argonaut Group, Mr. Richter held the position of Vice President, Human Resources for PG&E's National Energy Group from August 1997 to March 2001. Prior to joining PG&E, Mr. Richter held various senior management positions at Aquila Energy and Honeywell, Inc.

Houston C. Ross III was elected Vice President of Financial Analysis and Planning of Regency GP LLC in March 2007. From February 2004 until March 2007, Mr. Ross served as Director of Financial Analysis and Planning for Regency Gas Services LP and its predecessor. 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 B.S. in Mechanical Engineering.

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

A. Troy Sturrock was elected Vice President, Controller of Regency GP LLC in February 2008. From June 2006 to February 2008, Mr. Sturrock served as the Assistant Controller and Director of Financial Reporting and Tax for Regency GP LLC. From January 2004 to June 2006, Mr. Sturrock was associated with the Public Company Accounting Oversight Board, where he was an inspection specialist in the division of registration and inspections. Mr. Sturrock served in various roles at PricewaterhouseCoopers LLP from 1995 to 2004, most recently as a senior manager in the audit practice specializing in the transportation and energy industries. Mr. Sturrock is a Certified Public Accountant.

Ramon Suarez, Jr. was elected Vice President, Treasurer of Regency GP LLC in March 2007. From February 2006 to March 2007, 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. Mr. Suarez has over 21 years of financial experience.

Michael J. Bradley was elected to the Board of Directors of Regency GP LLC in January 2008. He has been the President and Chief Executive Officer of the Matrix Service Company since November 2006. Prior to joining Matrix Service Company, Mr. Bradley served as President and CEO of DCP Midstream Partners and was a member of the board. Mr. Bradley was named Group Vice President of Gathering and Processing for Duke Energy Field Services (DEFS) in 2004 and served as Executive Vice President (DEFS) from 2002 to 2004. From 1994 to 2002, he served as Senior Vice President (DEFS) and was responsible for business development and commercial activities. Mr. Bradley graduated from the University of Kansas with a Bachelor of Science degree in Civil Engineering. He also completed the Duke University Executive Management Program. Mr. Bradley is a member of the American Society of Civil Engineers. He also serves on the advisory board for the University of Kansas, School of Engineering.

James F. Burgoyne was elected to the Board of Directors of Regency GP LLC in June 2007. He is a Managing Director and global leader of GE Energy Financial Services' Diversified Energy business, which invests in mid- and downstream oil & gas infrastructure, producing oil, gas and coal reserves, and in a broad range of energy infrastructure in Europe. Mr. Burgoyne has headed this commercial unit within GE Energy Financial Services since it was formed in 2004. Prior to this position, Mr. Burgoyne was a Managing Director with GE Structured Finance's global energy team, where he was responsible for client development and the origination of business opportunities with US energy companies domestically and internationally. Before joining GE in 1997, Mr. Burgoyne was an Executive Director at SBC Warburg.

Daniel R. Castagnola was elected to the Board of Directors of Regency GP LLC in June 2007. He is a Managing Director at GE Energy Financial Services and is responsible for a team of professionals investing in North America. Additionally, Mr. Castagnola leads all equity origination efforts for GE Energy Financial Services in Latin America. Mr. Castagnola joined GE in 2002. Mr. Castagnola serves as a director of Port Berre, LLC, a gas storage company. Prior to joining GE, Mr. Castagnola worked for nine years at Enron Corp. in its international division and three years at KPMG.

Paul J. Halas was elected to the Board of Directors of Regency GP LLC in June 2007. From June 2006 to the present, Mr. Halas has served as a Managing Director and General Counsel of GE EFS. Mr. Halas served as the Senior Vice President Business Development at the National Grid USA Service Company Inc. from May 2005 to June 2006. From August 2003 to May 2005, Mr. Halas served as the President of GridAmerica LLC (Independent Electric Transmission Company, subsidiary of National Grid USA). He also served as Senior VP & General Counsel of GridAmerica LLC from May 2002 to August 2003. Prior to joining GridAmerica LLC, he held positions at Ropes & Gray, Oak Industries Inc., Timex Group Limited and All Energy Marketing Company LLC, a subsidiary of New England Electric System.

Mark T. Mellana was elected to the Board of Directors of Regency GP LLC in June 2007. He is a Managing Director at GE Energy Financial Services, and has been with the firm since 1999. Mr. Mellana has held various positions at GE Energy Financial Services and is currently a Managing Director—Operations and Development responsible for equity and development investments. Prior to joining GE, Mr. Mellana worked for the unregulated subsidiary of GPU, Inc. as the Director of Finance, Director of Mergers and Acquisitions and the Director of New Business Development. Mr. Mellana serves on a number of boards, including those of Source Gas LLC and Bobcat Gas Storage LLC.

John T. Mills was elected to the Board of Directors of Regency GP LLC in January 2008. He has served on the CONSOL Energy (NYSE: CNX) Board of Directors and as a member of the audit and compensation committees since 2006. Currently, he also serves as a member of the audit and corporate governance and nominating committees for Cal Dive International Inc. (NYSE: DVR), a marine construction company. Prior to his board appointments, Mills spent 30 years in numerous management and tax-related positions, including his most recent role as chief financial officer for Marathon Oil, until his retirement in 2003.

Brian P. Ward was elected to the Board of Directors of Regency GP LLC in June 2007. He is Managing Director and Chief Risk Officer for GE Energy Financial Services. In this role, he is responsible for underwriting and portfolio risk management for GE EFS's domestic and international assets. He has held this position since January 2004. Immediately prior to joining this unit, Mr. Ward served as Quality Leader for GE Structured Finance, the predecessor business of GE Energy Financial Services. Mr. Ward has worked for GE for more than 25 years. He has held a number of management roles in Risk, Finance and Business Development in a variety of industries and regions.

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.

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

Name	Title
James W. Hunt	President
Stephen L. Arata	Vice President
William E. Joor III	Vice President and Secretary
Richard D. Moncrief	Vice President
Lawrence B. Connors	Vice President
Martin Anthony	Vice President
Jacque L. Wolf	Vice President
Ramon Suarez, Jr.	Treasurer

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 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 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, 2007 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).

Table of Contents

Item 11. Executive Compensation

Background. HMTF Regency, a limited partnership owned by the HM Capital Investors, acquired RGS, the predecessor of the Partnership, on December 1, 2004. In connection with the acquisition, HMTF Regency authorized a special class of profits interests (the "Acquisition Profit Interests") as a source of potential compensation for a new management team for the new venture. The Acquisition Profit Interests represented economic interests in HMTF Regency only after a preferred 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 were customary in order to attract a highly experienced management team. At the time of our initial public offering in February 2006, each holder of an Acquisition Profit Interest entered into an exchange agreement pursuant to which each such holder exchanged his or her Acquisition Profit Interests for common and subordinated units of the Partnership as well as interests in the General Partner.

The following table sets forth the number of common units and subordinated units that the chief executive officer and the chief financial officer retained from their Acquisition Profits Interests and were held as of December 31, 2007, together with the aggregate amount of distributions paid to each of them for 2006 and 2007.

Name (1)(2)	Common Units	Subordinated Units	2006 Distributions	2007 Distributions
James W. Hunt (3)	173,993	840,678	$ 979,036	$ 1,425,606
Stephen L. Arata	49,712	240,194	279,619	424,023

(1) In connection with the exchange of the Acquisition Profit Interests, each of these officers also received indirect equity interests in the General Partner, as follows: Mr. Hunt — 3.2 percent; and Mr. Arata — 0.9 percent.

(2) None of the other named executive officers participated in the Acquisition Profit Interests, having begun their employment with the Partnership following its initial public offering.

(3) Includes 100,000 common units transferred by gift by Mr. Hunt to his two children immediately after our initial public offering.

The compensation committee of the board of directors of the General Partner does not consider the Acquisition Profit Interests to be continuing compensation to these officers. 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 Profit Interests and takes the value of the common and subordinated units received by these officers in exchange for the Acquisition Profit Interests into account in making awards under our LTIP.

Acquisition of General Partner by GE EFS. On June 18, 2007, Regency GP Acquirer LP ("GP Acquirer"), an indirect subsidiary of GECC (which owns all the outstanding Class A Units of GP Acquirer), acquired 91.3 percent of the member interest in our General Partner and the same percentage of the outstanding limited partner interests of our General Partner from affiliates of HM Capital, resulting in a change of control of the Partnership. Concurrently, GP Acquirer also acquired from members of management the remaining 8.7 percent of the member interest in our General Partner and the remaining 8.7 percent of the outstanding limited partner interests of our General Partner, thereby giving GP Acquirer 100 percent ownership interest in our General Partner.

Table of Contents

In the transaction with management, certain members of management, including our CEO and CFO, exchanged their interests in our General Partner for, or in a few cases purchased for cash, Class B Units in GP Acquirer that provide those members of management with an 8.2 percent economic interest in our General Partner. Other members of management sold their interests in our General Partner (aggregating 0.5 percent) for cash.

The compensation committee of the board of directors of the General Partner considers the Class B Units of GP Acquirer so acquired by members of management to be investments rather than compensation. Consequently, neither the values attributable to the units for which the awards were exchanged nor any distributions made with respect to those units are included in the summary compensation table.

In a concurrent transaction, another affiliate of GECC acquired 17,763,809 of our outstanding subordinated units (including 58,013 subsequently resold to management members), being all the outstanding other than 1,340,087 subordinated units that were retained, directly or indirectly, by certain members of management (including three officers who subsequently resigned) and 58,013 that were purchased from that affiliate by certain management members.

In connection with these transactions, the CEO and CFO, each of the named executive officers and 26 other officers and management employees entered into agreements with GP Acquirer pursuant to which each such employee was granted Class C Units, a separate class of securities of GP Acquirer. These Class C Units are structured as management incentive equity and the vesting of these units will entitle the holders to participate in quarterly distributions or incentive distributions by the Partnership received by GP Acquirer attributable to the interests in our General Partner owned by GP Acquirer. The Class C Units, as a whole, will participate in those distributions received by GP Acquirer based on the level of distributable cash per unit produced by the Partnership (without regard to incentive distribution rights): At the annual level of less than $2.50 per unit, no participation; $2.50 - $2.74, two percent of the distributions received; $2.75 - $2.99, five percent of the distributions received; and $3.00 or more, ten percent of the distributions received. The Class C Units vest at the time a level of participation is achieved and vest at that level (until another level is achieved). If the employment of a holder of Class C Units (other than Mr. Hunt) is terminated for any reason, including death or disability, any unvested Class C Units will be forfeited to GP Acquirer and will be available for reissuance.

The receipt of any distributions with respect to the Class C Units of GP Acquirer is subject to contingencies relating to the levels of cash available for distribution by the Partnership on the common units and to the continued employment of the holders of the units. The Class C Units are not yet entitled to any distributions. Accordingly, no value has been assigned to the Class C Units and none has been included in the summary compensation table.

In connection with these transactions, all outstanding, unvested LTIP awards at the time of the GE EFS Acquisition vested upon the change of control of the General Partner. As a result, the Partnership recorded a one-time charge of $11,928,000 during the three months ended June 30, 2007. LTIP awards granted subsequent to the GE EFS Acquisition vest equally over four years.

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.

Table of Contents

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 General Partner considers the success of the Partnership in achieving its business strategies.

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. The most important of these are (i) 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 and (ii) cash available for distribution. 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 of our board of directors is directly responsible for our compensation programs, which include programs that are designed specifically for (1) our most senior executive officers, or senior officers, including 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 is charged, among other things, with the responsibility of reviewing the General Partner's executive officer compensation policies and practices. These compensation programs for executive officers consist of base salary, annual incentive bonus and LTIP awards in the form of equity-based restricted units, as well as other customary employment benefits. Total compensation of executive officers of the General Partner and the relative emphasis of the three main components of annual compensation are reviewed and established on an annual basis by the compensation committee.

At the beginning of each fiscal year, our board, based on information and recommendations provided by management, approves corporate objectives for the Partnership, including a budget, for the year. These corporate objectives may differ from, and may be greater than, the projections of the anticipated performance of the Partnership provided by the General Partner to the investing public from time to time. The board also at this time determines the magnitude of the incentive bonus pool to be paid to officers and employees for the preceding year.

It is the practice of the compensation committee to meet, in one or more meetings, at about the same time for several purposes. These include (i) assessing the performance of the CEO and other senior officers with respect to the Partnership results for the prior year, (2) reviewing and assessing the personal performance objectives of the senior officers for the preceding year, and (3) determining the amount of the bonus pool approved by the board of directors to be paid to the senior officers after taking into account both the target bonus levels established for those senior officers at the outset of the preceding year and the foregoing performance factors.

In addition, the compensation committee, at these meetings and after taking into account both the advice of outside consultants and recommendations of management, sets base salary levels for the senior officers and the target bonus levels for those officers (representing the bonus that may be awarded and expressed as a percentage of base salary for the year). The compensation committee also considers recommendations to be made to the board of directors regarding awards to senior officers, as well as other employees, under the LTIP for the ensuing fiscal year.

Table of Contents

During all of 2006 and 2007, the compensation committee of our board of directors was composed of three non-management directors. In January 2008, the compensation committee was reconstituted and currently includes three non-management directors and the CEO. The CEO will not participate in decisions relating to his own compensation.

Compensation Advisors. In January 2007, we retained the Hay Group as an independent consultant with respect to compensation of senior officers and general compensation programs. The Hay Group 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, including Atlas Pipeline, Copano Energy, Crosstex Energy, Inc., Energy Transfer Partners, L.P., Holly Corporation, Midwest Energy Partners LP, Martin Midstream and TEPPCO Partners. It also provided guidance on industry best practices. The Hay Group provided information and advice to management and the compensation committee in connection with (1) the determination of base salaries for senior officers for 2007 and (2) setting individual goals and targeted award levels for senior officers for 2007. The Hay Group did not advise either the compensation committee or management regarding the determination of individual awards for 2007 under our LTIP for the senior officers.

In 2008, the compensation committee retained The Hay Group as an independent consultant with respect to senior officer compensation and general compensation programs. The Hay Group has not completed its evaluation as of February 28, 2008.

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. As a consequence, the compensation committee evaluates the performance of the Partnership against the various metrics set forth under "—Reward Objectives," considers 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, annual incentive 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 significant 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.

Components of Compensation

Base Salary and Annual Incentive Bonuses. In determining base salary for each executive officer, the compensation committee considers the executive's experience and position within the 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 CEO, or, in the case of the CEO, the recommendation of the chairman of the compensation committee. While the CEO is currently a member of the compensation committee, he does not participate in setting his compensation.

57

Table of Contents

At the beginning of each fiscal year, our board approves annual corporate objectives, including a budget. The annual corporate objectives may differ from, and may be greater than, the guidance regarding the anticipated Partnership performance for the year. These objectives, along with personal performance objectives, are reviewed at the end of the year for the purpose of determining annual incentive bonuses. In addition to the reward objectives outlined above, 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.

Determination of the CEO’s annual incentive bonus is significantly influenced by the extent of the achievement of corporate objectives, and determination of the annual incentive bonuses of the other executive officers are significantly influenced by the extent of the achievement of corporate objectives and the achievement of individual objectives.

We choose to pay salaries and incentive bonuses to recognize an employee’s role, responsibilities, skills, experience and performance. Until the initial public offering of the Partnership in February 2006, 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, fund organic growth, and service our 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.

Equity-Based Awards. A portion of executive officer compensation (as well as compensation of senior managers) is 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. 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.

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. Options awarded under our LTIP in 2006 and prior to June 2007 vested upon the change in control of the Partnership.

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 after June 18, 2007 under our LTIP vest as to one-fourth of the award on each of the first four anniversaries of the date of the award. Restricted units participate in distributions on the same basis as other common units.

Deferred Compensation. The only deferred compensation element of our compensation program is our 401(k) plan. The plan does not constitute a major element of our compensation structure.

Perquisites. Perquisites are not a significant factor in our compensation structure.

Compensation Events

Salary. At a meeting of the compensation committee in March 2007, the compensation committee made no change to the base salaries of the named executive officers but continued them as in 2006: CEO ($400,000); CFO ($250,000); Mr. Moncrief ($200,000); Mr. Davis ($200,000); and Mr. Miller ($130,000). At its meeting on June 18, 2007, the Board of Directors approved base salary increases in connection with their respective promotions to their current positions for Mr. Moncrief and Mr. Miller to $275,000 and $170,000 per year, respectively. The responsibilities and salaries of all other NEOs remained unchanged.

Table of Contents

Bonus. At a meeting of the compensation committee held January 23, 2007, the officers of the General Partner offered to forgo all their bonuses under the 2006 bonus plan in excess of holiday 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 2006 summary compensation table for these individuals includes no bonuses for the named executive officers other than holiday bonuses. Mr. Miller received a bonus payment in excess of his holiday bonus as he was not an officer of the General Partner in 2006.

In March 2007, the compensation committee established the 2007 target bonus levels for the CEO, CFO and NEOs were as follows: Mr. Hunt-100 percent of base salary ($400,000); Mr. Arata-75 percent of base salary ($187,500); Mr. Moncrief-75 percent of base salary ($150,000); Mr. Davis -75 percent of base salary ($150,000); and Mr. Miller-25 percent of base salary ($32,500). (While the base salaries had been increased, the target bonus levels remained the same as in 2006.)

At its meeting on June 18, 2007, the Board of Directors increased the annual bonus targets for Mr. Moncrief to 100 percent of his then base salary ($275,000) and Mr. Miller to 50 percent of his then base salary ($85,000), each in connection with his promotion to his current position.

At its February 2008 meeting, the Compensation Committee approved the payment of bonuses to officers and other general and administrative employees at a rate of 62 percent of target levels, based on the Partnership’s financial performance during 2007. In making this decision, the Compensation Committee recognized the progress that the Partnership made during the year with respect to acquisitions, organic growth and debt and equity financings but noted that the Partnership was forced to reduce its projections of performance to the investment community in the fourth quarter of the year. Mr. Hunt volunteered to forego receipt of any bonus for 2007.

Equity-Based Awards. At the time of our initial public offering, the General Partner adopted our LTIP for employees (including executive officers), consultants and directors of the 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 percent 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 Profits Interests holders (who included Mr. Hunt, Mr. Arata and all of our other executive officers at the time of our initial public offering); 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 awards of 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 Profits Interests 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 (but no restricted units). All other employees (approximately 150 individuals) received awards representing 57 percent of the units awarded and 79 percent of the value of the awards.

Table of Contents

For the balance of 2006, awards were made under the LTIP primarily (i) to attract and retain employees and (ii) to employees of TexStar. A few retention awards were made to non-officer employees.

On March 8, 2007, pursuant to recommendations by management, the compensation committee made additional awards under the LTIP to 33 employees (which awards included 35,000, 10,000 and 10,000 restricted units awarded to Messrs. Moncrief, Davis and Miller, being the only named executive officers who received any of these awards). In accordance with the views of the compensation committee that the units acquired by the CEO and CFO in exchange for Acquisition Profits Interests provided sufficient performance incentive for the present, neither of them was granted any additional award under the LTIP. The other NEOs, not holding Acquisition Profit Interests, were granted restricted unit awards in 2007.

On June 18, 2007, with the acquisition of ownership of the General Partner by GE EFS, all options and restricted stock awards then outstanding under the LTIP vested in full. In contemplation of that result, and after consultation with GE EFS, the compensation committee approved a new award of 355,000 restricted units to 45 employees (none of whom included any of the named executive officers other than Mr. Miller who received an award of 15,000 restricted units) as an incentive to management and key employees, effective as of June 26, 2007

On January 24, 2008, the compensation committee approved a new award of 175,000 restricted units to CDM employees as an incentive to management and key employees. In addition, the three founders of CDM, together with eight other management or key employees of CDM, were awarded Class C Units of GP Acquirer that, in the aggregate, represent 24.2 percent of the pool of such units.

Potential Payments. As indicated under "—Acquisition of General Partner by GE EFS," the transaction by which GP Acquirer acquired the entire equity ownership of our General Partner on June 18, 2007 constituted a change of control under our LTIP. As a result, all then unvested outstanding restricted stock and option awards under that plan vested on that date. Since that date, of the named executive officers, including our CEO and CFO, only Mr. Miller has received an award under our LTIP. As indicated under "—Equity Based Awards," Mr. Miller received an award of 15,000 restricted units on June 28, 2007. These units vest 25 percent annually over the four years following the date of the award. If Mr. Miller's employment had terminated on December 31, 2007 by reason of his death or disability, by us "without cause" or as a result of a change in control on that date, all of his 15,000 outstanding unvested restricted units under our LTIP would have automatically vested, resulting in a realized value of $500,550 based upon the closing sales price of our common units on NASDAQ on December 31, 2007. This is the only potential payment to any named executive officer that would be due upon termination or a change of control at December 31, 2007.

Summary Compensation Table. The following table summarizes, with respect to our CEO, CFO and NEOs, information relating to the compensation earned for services rendered during 2007 and 2006.

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($)(1)(3)	Option Awards ($)(1)(3)	All Other Compensation ($)(2)(4)(5)	Total ($)
James W. Hunt	2007	400,000	-	-	79,954	9,334	489,288
President, Chief Executive Officer and Chairman of the Board	2006	386,667	10,000	-	35,046	7,600	439,313
Stephen L. Arata	2007	250,000	127,875	-	27,987	10,324	416,186

Executive Vice President and Chief Financial Officer	2006	245,833	6,250	-	12,266	6,250	270,599
Richard D. Moncrief	2007	237,500	187,550	1,814,660	43,584	50,115	2,333,409
Executive Vice President and Chief Operating Officer	2006	145,513	5,000	269,840	13,916	1,500	435,769
Charles M. Davis, Jr.	2007	200,000	93,000	1,406,027	42,686	50,910	1,792,623
Senior Vice President, Corporate Development	2006	160,641	5,000	360,473	15,814	-	541,928
David T. Miller	2007	155,000	39,525	755,531	4,001	38,089	992,146
Vice President, Engineering	2006	119,167	17,875	182,466	17,449	3,313	340,270

1 The amounts included in the "Unit Awards" and "Option Awards" columns reflect the dollar amount of compensation expense we recognized with respect to these awards for the fiscal years ended December 31, 2007 and December 31, 2007, respectively, in accordance with SFAS 123(R). These amounts reflect our accounting expense for these awards, and do not correspond to the actual value that will be recognized by the named executives. The material terms of our outstanding LTIP awards to our executive officers are described in "Compensation Discussion and Analysis — Components of Compensation — Equity Based Awards."

2 The amounts include distribution payments on unvested restricted units to Mr. Moncrief ($44,466), Mr. Davis ($50,550) and Mr. Miller ($34,050).

3 All the restricted units and options held by Messrs. Moncrief, Davis and Miller (other than the 15,000 restricted units awarded to Mr. Miller in late June 2007) vested on the change in control of the Partnership that occurred on June 18, 2007. This vesting is reflected in the compensation amounts shown for those individuals in the table under Unit Awards and Option Awards.

4 The Partnership does not provide perquisites or other personal benefits to any named executive officer exceeding $10,000.

5 The Partnership makes contributions on behalf of the named executive officers to the Partnership's 401(k) plan on the same basis as all other employees and these amounts are included in All Other Compensation.

Grants of Plan Based Awards. The following table provides information concerning each grant of an award made to our NEOs in the last completed fiscal year under any plan, including awards that have been transferred.

Name	Grant Date	All Other Stock Awards: Number of Shares of Stock or Units (#)	Grant Date Fair Value of Stock and Option Awards ($)(1)
James W. Hunt	n/a	-	$ -

Stephen L. Arata	n/a	-	-
Richard D. Moncrief	3/8/2007	35,000	969,500
Charles M. Davis, Jr.	3/8/2007	10,000	277,000
David T. Miller	3/8/2007	10,000	277,000
David T. Miller	6/26/2007	15,000	473,700

(1) The grant date price equals the closing price per common unit on NASDAQ.

Table of Contents

Outstanding Equity Awards at December 31, 2007

	Option Awards			Stock Awards(1)	
Name (a)	Number of Securities Underlying Unexercised Options (#) Exercisable (b)(1)	Option Exercise Price ($) (e)(2)	Option Expiration Date (f)	Number of Shares or Units of Stock That Have Not Vested (#) (g)(3)	Market Value of Shares or Units of Stock That Have Not Vested ($) (h)(4)
James W. Hunt	100,000	$ 20.00	1/31/2016	-	$ -
Stephen L. Arata	35,000	20.00	1/31/2016	-	-
Richard D. Moncrief	50,000	22.30	4/10/2016	-	-
Charles M. Davis, Jr.	50,000	19.86	3/10/2016	-	-
David T. Miller	5,000	20.00	1/31/2016	15,000	500,550

(1) All unvested awards then outstanding under our LTIP on June 18, 2007, including both options and restricted units, vested in full as a result of the change in control of the Partnership that occurred on that date.
(2) The exercise price is the "closing sales price" of a common unit on the effective date of the grant (or, if there was no trading on that date, the preceding date on which there was trading).
(3) These restricted units vest 25 percent annually from the date of grant.
(4) Based on the closing sales price of our common units on December 31, 2007 of $33.37.

Option Exercises and Restricted Unit Vesting. The following table depicts the number and amount of awards that were exercised or vested during the year ended December 31, 2007.

	Unit Awards	
Name	Number of Units Acquired on Vesting (#)	Value Realized Upon Vesting ($)(1)
James. W. Hunt	-	$ -
Stephen L. Arata	-	-
Richard D. Moncrief	85,000	2,144,550
Charles M. Davis, Jr.	85,000	2,144,550
David T. Miller	40,000	1,009,200

(1) Based on the closing sales price of our common units of $25.23 on June 18, 2007, the date of change of control of the Partnership.

Table of Contents

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. Since our initial public offering, related party transactions involving the Partnership or any of its subsidiaries include those that were disclosed in connection with that offering, our acquisition of TexStar Field Services, L.P. from an affiliate of HM Capital, and our acquisition of FrontStreet from an affiliate of GECC, the latter two of which were approved by the conflicts committee of our board. With respect to HM Capital, the only continuing transactions are those under gas purchase contracts executed in connection with the acquisition of TexStar involving our purchase of natural gas for processing from an affiliate of HM Capital.

We sublease office space in San Antonio, Texas from an affiliate of HM Capital. The annual rental of that space is at the same rental rate paid by the lessee and is $151,000. This transaction was approved in accordance with our related party transaction policy.

Our officers hold the following investments in the Partnership either through cash contributions, vested LTIP awards, or the exchange of Acquisition Profits Interests for common units, subordinated units and general partner interest. These named executive officers acquired their interests in GP Acquirer pursuant to the transactions involving the change of control of the Partnership at June 18, 2007, some of whom (Messrs. Hunt and Arata) exchanged their interests in our General Partner for the Class B Units of GP Acquirer and the others purchased their interests in the Class B Units.

Name	General Partner Interest (Class B)(1)	Common Units	Subordinated Units(2)
James W. Hunt	$ 6,994,507	$ 5,219,790	$ 11,179,171
Stephen L. Arata	1,970,673	1,491,360	4,116,106
Richard D. Moncrief	1,200,000	1,067,640	300,000
Charles M. Davis, Jr.	800,000	2,772,210	199,992
David T. Miller	250,000	615,300	62,496

(1) The Class B Units of GP Acquirer were valued at the original investment, common units were valued at $30 per unit (approximating current market value) and subordinated units were valued at $24 per unit (equal to the sale price in the GE EFS transaction).
(2) In the GE EFS transaction, Mr. Hunt and Mr. Arata each sold a portion of his holdings of subordinated units for $11,179,171 and $2,216,364, respectively.

Directors' Compensation. The directors of the General Partner who are not employees of the General Partner or affiliated with the General Partner's controlling security holder received in 2007 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 General Partner. Determinations as to any such participation are made by the non-participating directors.

Table of Contents

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, 2007.

Name (a)	Fees Earned or Paid in Cash ($) (b)	Stock Awards ($) (c)(1)	Option Awards ($) (d)(2)	Total ($) (h)
Joe Colonnetta	18,500	-	-	$ 18,500
Jason H. Downie	21,000	-	-	21,000
A. Dean Fuller	35,500	69,444	4,001	108,945
Jack D. Furst	14,500	-	-	14,500
J. Edward Herring	18,500	-	-	18,500
Robert D. Kincaid	18,500	69,444	4,001	91,945
Gary W. Luce	20,000	69,444	4,001	93,445
Robert W. Shower	9,250	33,300	168	42,718
J. Otis Winters	40,000	69,444	4,001	113,445
James F. Burgoyne	-	-	-	-
Daniel R. Castagnola	-	-	-	-
Paul J. Halas	-	-	-	-
Mark T. Mellana	-	-	-	-
Brian P. Ward	-	-	-	-

(1) Each amount shown represents the earned portion 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 the fiscal year ended December 31, 2007 in accordance with the Statement of Financial Accounting Standards No. 123(R).

(2) Each amount shown represents options 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 $1.15 per common units. The amounts included in the “Option Awards” column include the dollar amount of compensation expense we recognized for the fiscal year ended December 31, 2007 in accordance with FAS 123(R).

Mr. Colonnetta, Mr. Downie, Mr. Furst, and Mr. Herring are officers of HM Capital, a related party. All fees paid to these directors were remitted directly to HM Capital. Mr. Burgoyne, Mr. Castagnola, Mr. Halas, Mr. Mellana, and Mr. Ward are officers of GE EFS.

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, 2007 to be filed pursuant to Section 13(a) of the Securities and Exchange Act of 1934 (the “Annual Report”). Based on those reviews and discussions, we recommend to the board of Directors of the General Partner that the compensation discussion and analysis be included in the Annual Report.

Compensation Committee
Mark T. Mellana, Chairman
Michael J. Bradley
Paul J. Halas
James W. Hunt

Table of Contents

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.
The following table sets forth, as of February 7, 2008, 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.

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	Subordinated Units	Percentage of Outstanding Subordinated Units	Class D Common Units	Percentage of Outstanding Class D Common Units	Class E Common Units	Percentage of Outstanding Class E Common Units	Percentage of Total Units
HM Capital	8,098,570	19.9%	-	*	-	*	-	*	11.3%
Aircraft Services Corp(4)	-	*	17,705,796	92.7%	-	*	4,701,034	100.0 %	31.2%
CDMR Holdings LLC(3)	-	*	-	*	7,276,476	100.0 %	*	*	10.1%
Kayne Anderson Capital Advisors, L.P.	3,612,994	8.9%	-	*	-	*	-	*	5.0%
Swank Advisors	3,102,273	7.6%	-	*	-	*	-	*	4.3%
Neuberger Berman LLC	2,604,907	6.4%	-	*	-	*	-	*	3.6%
James W. Hunt(1)(2)	173,993	0.4%	465,799	2.4%	-	*	-	*	0.9%
Stephen L. Arata(1)(2)	84,712	0.2%	171,504	0.9%	-	*	-	*	0.4%
Rick Moncrief(1)	65,988	0.2%	12,500	*	-	*	-	*	0.1%
	132,407	0.3%	8,333	*	-	*	-	*	0.2%

Charles M. Davis Jr.(1)									
David T. Miller(1)	20,510	*	2,604	*	-	*	-	*	*
Michael T. Bradley	-	*	-	*	-	*	-	*	*
James F. Burgoyne	-	*	-	*	-	*	-	*	*
Daniel R. Castagnola	-	*	-	*	-	*	-	*	*
Paul J. Halas	-	*	-	*	-	*	-	*	*
Mark T. Mellana	-	*	-	*	-	*	-	*	*
John T. Mills	-	*	-	*	-	*	-	*	*
Brian P. Ward	-	*	-	*	-	*	-	*	*
J. Otis Winters(1)	15,000	*	-	*	-	*	-	*	*
All directors and executive officers as a group (19 persons)	736,140	1.8%	996,405	97.9%	-	*	-	*	27.1%
Total number of units as of February 7, 2008	40,704,020		19,103,896		4,701,034		7,276,506		

(1) The common units amounts include unit options which are currently exercisable in the following amounts of common units: Mr. Hunt — 100,000; Mr. Arata — 35,000; Mr. Moncrief — 50,000; Mr. Davis — 50,000; Mr. Rozzell — 5,00 and Mr. Winters — 5,000.

(2) 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; and Mr. Arata - 4,897 common and 23,659 subordinated.

(3) CDMR Holdings, LLC is owned by four entities: two investment limited partnerships affiliated with Carlyle/Riverstone Global Energy and Power Fund II, L.P. (collectively the "Carlyle/Riverstone Entities"), and two entities owned primarily by certain members of management of our contract compression segment (the "Management Entities"). The Carlyle/Riverstone Entities and the Management Entities have a 67% and a 33% ownership interest in CDMR Holdings, LLC, respectively. The Carlyle/Riverstone Entities are C/R CDM Holdings II, L.P. and C/R CDM Investment Partnership III, L.P. The Carlyle/Riverstone Entities are associated with Riverstone Holdings LLC ("Riverstone") and The Carlyle Group ("Carlyle"). The address of the Carlyle/Riverstone Entities and Riverstone is 712 Fifth Avenue, 51st Floor, New York, NY 10019. The address of Carlyle is 1001 Pennsylvania Avenue, N.W., Suite 200, Washington, D.C. 20004. The Carlyle/Riverstone Entities are ultimately controlled by a management committee. The Management Entities are CDM Investments, Ltd. and CDM Compression, LLC.

(4) Aircraft Services Corp is an affiliate of GECC.

* Ownership percentages are less than 0.1 percent.

Table of Contents

Securities Authorized for Issuance under Equity Compensation Plans. The following table provides information concerning common units that may be issued under the General Partner Long-Term Incentive Plan ("LTIP"). 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 General Partner.

Our General Partner's board of directors, or its compensation committee, in its discretion may terminate, suspend or discontinue the LTIP at any time with respect to any award that has not yet been granted. Our General Partner's board of directors, or its compensation committee, also has the right to alter or amend the LTIP or any part of the plan from time to time, including increasing the number of units that may be granted subject to unitholder approval as required by the exchange upon which the 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.

The following table summarizes the number of securities remaining available for future issuance under the LTIP plan as of February 7, 2008.

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			
Long-Term Incentive Plan(1)	705,268	25.72	581,184
Total	705,268	$ 25.72	581,184

(1) The long-term incentive plan, which did not require approval by our limited partners, currently permits the grant of awards covering an aggregate of 2,865,584 units. For more information about our long-term incentive plan, refer to Item 11. "Executive Compensation-Components of Compensation".

Table of Contents

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

Transactions with Related Persons. The employees operating the assets of the Partnership and its subsidiaries and all those providing staff or support services are employees of the General Partner. Pursuant to the Partnership Agreement, the General Partner receives a monthly reimbursement for all direct and indirect expenses incurred on behalf of the Partnership. Reimbursements of $27,628,000 were recorded in the Partnership's audited consolidated financial statements during the year ended December 31, 2007, as operating expenses or general and administrative expenses, as appropriate.

HM Capital and its affiliates are considered to be a related parties. BBOG, an affiliate of HM Capital, is a natural gas producer on the Partnership's gas gathering and processing system. All of our related party receivables, payables, revenues and expenses as disclosed in the audited consolidated financial statements relate to BBOG. BBE, a wholly owned subsidiary of HM Capital, subleases office space to us for which we paid $151,000 in the year ended December 31, 2007.

In conjunction with distributions by the Partnership on common and subordinated units, together with the general partner interest, HM Capital and affiliates received cash distributions of $24,392,000 during the year ended December 31, 2007, as a result of their ownership in the Partnership.

As a part of the GE EFS Acquisition, affiliates of HM Capital entered into an agreement to hold 4,692,417 of the Partnership's common units for a period of 180 days. In addition, a separate affiliate of HM Capital Partners entered into an agreement to hold 3,406,099 of the Partnership's common units for a period of one year.

Concurrently with the GE EFS acquisition, eight members of the senior management of the General Partner, together with two independent directors, entered into an agreement to sell an aggregate of 1,344,551 subordinated units to an affiliate of GE EFS for $24.00 per unit. Additionally, an affiliate of GE EFS entered into a subscription agreement with four officers and certain other members of management of the General Partner, whereby these individuals acquired an 8.2 percent indirect economic interest in the General Partner.

Concurrently with the Partnership's issuance of common units in July and August 2007, GE EFS and certain members of the Partnership's management made a capital contribution aggregating $7,735,000 to maintain the General Partner's two percent interest in the Partnership.

In conjunction with distributions by the Partnership on common and subordinated units, together with the general partner interest, GE EFS and affiliates received cash distributions of $14,592,000 during the year ended December 31, 2007, as a result of their ownership in the Partnership.

As of February 7, 2008, Aircraft Services Corp, an affiliate of GECC, owns 4,701,034 Class E common units and 17,705,796 subordinated units, representing a 31.2 percent limited partner interest in us.

The General Partner, on behalf of the Partnership, is currently negotiating the terms of a lease agreement pursuant to which it will lease office space for the principal executive offices of the Partnership at a location different from its current lease. The real property broker representing the Partnership, selected by the General Partner after a request for proposals, is owned by the son-in-law of our CEO. Under the terms of the brokerage agreement between the broker and the Partnership, no brokerage fee is payable by the Partnership as tenant, all such fees being payable by the landlord. A portion (25%) of the brokerage fee paid by the landlord to the broker may be remitted to the Partnership or, to the extent that the Partnership deems the broker's services to exceed expectations, be retained by the broker. The entire brokerage fee is expected to be in the range of $400,000.

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 amounts 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 (which obligation has now expired); and
§ certain income tax liabilities attributable to the operation for the assets contributed to us prior to the time they were contributed.

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.

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.

Table of Contents

Item 14. Principal Accounting Fees and Services

Appointment of Independent Registered Public Accountant. The Audit Committee appointed KPMG LLP as our principal accountant to conduct the audit of our financial statements for the year ended December 31, 2007 on June 26, 2007. Deloitte & Touche LLP served as our independent registered public accountant for the year ended December 31, 2006.

Audit Fees. The following table sets forth fees billed by KPMG LLP and Deloitte & Touche LLP for the professional services rendered for the audits of our annual financial statements and other services rendered for the years ended December 31, 2007 and 2006:

	KPMG LLP December 31,		Deloitte & Touche LLP December 31,	
	2007	2006	2007	2006
	(in thousands)			
Audit fees (1)	$ 2,062	$ -	$ 335	$ 1,419
Audit related fees (2)	50	-	53	19
Tax fees (3)	-	-	211	45
All other fees(4)	-	-	-	-
Total	$ 2,112	$ -	$ 599	$ 1,483

(1) Includes fees for audits of annual financial statements, including the audit of internal controls over financial reporting, 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.

(2) Includes fees related to consultations concerning financial accounting and reporting standards in 2007 and 2006 and services related to the implementation of our internal controls over financial reporting in 2006.

(3) 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, 2007 and 2006.

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

Procedures for Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of Independent Registered Public Accountant. 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, 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.

Table of Contents

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 KPMG LLP or 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.

(a)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.

(a)3. Exhibits. See "Index to Exhibits".

Table of Contents

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 ENERGY PARTNERS LP
By: REGENCY GP LP, its general partner
By: REGENCY GP LLC, 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 James W. Hunt	Chairman, President, and Chief Executive Officer (Principal Executive Officer)	February 28, 2008
/s/ Stephen L. Arata Stephen L. Arata	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 28, 2008
/s/ Lawrence B. Connors Lawrence B. Connors	Senior Vice President, Finance and Accounting (Principal Accounting Officer)	February 28, 2008
/s/ Michael J. Bradley	Director	February 28, 2008

Michael J. Bradley		
/s/ James F. Burgoyne James F. Burgoyne	Director	February 28, 2008
Daniel Castagnola	Director	
/s/ Paul J. Halas Paul J. Halas	Director	February 28, 2008
/s/ Mark T. Mellana Mark T. Mellana	Director	February 28, 2008
John T. Mills	Director	
Brian P. Ward	Director	
J. Otis Winters	Director	

Table of Contents

Index to Exhibits

Exhibit Number	Description	Incorporated by Reference from Form	Date Filed or File No.
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	8-K	August 14, 2006
2.2	Stock Purchase Agreement by and among Regency Energy Partners LP, Pueblo Holdings, Inc., as Buyer, Bear Cub Investments, LLC, the Members of Bear Cub Investments, LLC identified herein, as Sellers, and Robert J. Clark, as Sellers' Representative dated April 2, 2007	8-K	April 3, 2007
2.3	Agreement and Plan of Merger among CDM Resource Management, Ltd., the Partners thereof, as listed on the signature pages hereof, Regency Energy Partners LP and ADJHR, LLC dated as of December 11, 2007	8-K	December 11, 2007
2.4	Contribution Agreement by and among Regency Energy Partners LP, Regency Gas Services LP, as Buyer, and ASC Hugoton LLC and FrontStreet EnergyOne LLC as Sellers dated December 10, 2007 and joined in by Aircraft Services Corporation (solely for purposes of Section 2.3(g) hereof)	8-K	December 10, 2007
3.1	Certificate of Limited Partnership of Regency Energy Partners LP	S-1	333-128332
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)	S-1	333-128332
3.2.1	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Regency Energy Partners LP	8-K	August 14, 2006
3.2.2	Amendment No. 2 to Amended and Restated Agreement of Limited Partnership of Regency Energy Partners LP	8-K	September 21, 2006
3.2.3	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Regency Energy Partners LP	8-K	January 7, 2008
3.2.4	Amendment No. 4 to Amended and Restated Agreement of Limited Partnership of Regency Energy Partners LP	8-K	January 15, 2008
3.3		S-1	333-128332

	Certificate of Formation of Regency GP LLC		
3.4	Form of Amended and Restated Limited Liability Company Agreement of Regency GP LLC	S-1	333-128332
3.5	Certificate of Limited Partnership of Regency GP LP	S-1	333-128332
3.6	Form of Amended and Restated Limited Partnership Agreement of Regency GP LP	S-1	333-128332
4.1	Form of Common Unit Certificate	S-1	333-128332
4.2	Indenture for 8 3/8 percent Senior Notes due 2013, together with the global notes	10-K	March 30, 2007
10.1	Regency GP LLC Long-Term Incentive Plan	S-1	333-128332
10.2	Form of Grant Agreement for the Regency GP LLC Long-Term Incentive Plan — Unit Option Grant	S-1	333-128332
10.3	Form of Grant Agreement for the Regency GP LLC Long-Term Incentive Plan — Restricted Unit Grant	S-1	333-128332
10.4	Form of Grant Agreement for the Regency GP LLC Long-Term Incentive Plan — Phantom Unit Grant (With DERS)	S-1	333-128332
10.5	Form of Grant Agreement for the Regency GP LLC Long-Term Incentive Plan — Phantom Unit Grant (Without DERS)	S-1	333-128332
10.6	Form of Contribution, Conveyance and Assumption Agreement	S-1	333-128332
10.7	Executive Employment Agreement dated December 1, 2004 between the Registrant and James W. Hunt	S-1	333-128332
10.8	Employment Agreement dated December 1, 2004 between the Registrant and Michael L. Williams	S-1	333-128332
10.9	Severance Agreement dated January 1, 2005 between the Registrant and William E. Joor, III	S-1	333-128332
10.10	Ground Lease Agreement (Lakin Plant)	S-1	333-128332
10.11	Ground Lease Agreement (Mocane Plant)	S-1	333-128332
10.12	Lisbon Lease Agreement	S-1	333-128332
10.13†	Firm Transportation Agreement dated June 8, 2005 between Regency Intrastate Gas LLC and Anadarko Energy Services Company	S-1	333-128332
10.14	Form of Indemnification Agreement between Regency GP LLC and	S-1	333-128332

	Indemnities		
10.15	Financial Advisory Agreement	S-1	333-128332
10.16	Monitoring and Oversight Agreement	S-1	333-128332
10.17	Form of Omnibus Agreement	S-1	333-128332
10.18	Form of Fourth Amended and Restated Credit Agreement of Regency Gas Services LP	8-K	August 14, 2006
10.19	Form of Amendment Agreement No. 3 with respect to the Fourth Amended and Restated Credit Agreements of Regency Gas Services LP dated September 28, 2007	8-K	October 3, 2007
10.20	Form of Amendment Agreement No. 4 with respect to the Fourth Amended and Restated Credit Agreements of Regency Gas Services LP dated January 15, 2008	8-K	February 12, 2008
10.21	Form of Amendment Agreement No. 5 with respect to the Fourth Amended and Restated Credit Agreements of Regency Gas Services LP dated February 14, 2008	8-K	February 19, 2008
12.1	Computation of Ratio of Earnings to Fixed Charges		
14.1	Code of Business Conduct	10-K	March 30, 2007
16.1	Letter from Deloitte & Touche LLP to the Securities and Exchange Commission dated June 18, 2007	8-K	June 19, 2007
21.1	List of Subsidiaries of Regency Energy Partners LP		
23.1	Consent of KPMG LLP		
23.2	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.		

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

††Incorporated by reference to the signature page of this filing.

Table of Contents

Index to Consolidated Financial Statements

Table of Contents

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 sheet of Regency Energy Partners LP and subsidiaries as of December 31, 2007, and the related consolidated statements of operations, comprehensive loss, cash flows, and partners' capital for the year then ended. These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Regency Energy Partners LP and subsidiaries as of December 31, 2007, and the results of their operations and their cash flows for the year ended December 31, 2007, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Regency Energy Partners LP's internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 28, 2008 expressed an unqualified opinion on the effectiveness of the Partnership's internal control over financial reporting.

/s/ KPMG LLP

Dallas, Texas
February 28, 2008

Table of Contents

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 Regency Energy Partners LP's internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Regency Energy Partners LP's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Regency Energy Partners LP maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Regency Energy Partners LP as of December 31, 2007, and the related consolidated statements of operations, comprehensive loss, cash flows, and partners' capital for the year ended December 31, 2007, and our report dated February 28, 2008 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Dallas, Texas
February 28, 2008

F-3

Table of Contents

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 sheet of Regency Energy Partners LP and subsidiaries (the "Partnership") as of December 31, 2006, 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. 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 the results of the Partnership's operations and cash flows for the years ended December 31, 2006 and 2005, 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 (February 28, 2008 as to Note 4)

Table of Contents

Regency Energy Partners LP
Consolidated Balance Sheets
(in thousands except unit data)

	December 31, 2007	December 31, 2006
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 27,822	$ 9,139
Restricted cash	6,029	5,782
Accrued revenues and accounts receivable, net of allowance of $55 in 2007 and $181 in 2006	129,908	96,993
Related party receivables	61	755
Assets from risk management activities	-	2,126
Other current assets	6,595	5,279
Total current assets	170,415	120,074
Property, plant and equipment		
Gas plants and buildings	134,300	103,490
Gathering and transmission systems	650,373	529,776
Other property, plant and equipment	105,399	73,861
Construction-in-progress	32,296	85,277
Total property, plant and equipment	922,368	792,404
Less accumulated depreciation	(104,314)	(58,370)
Property, plant and equipment, net	818,054	734,034
Other Assets:		
Intangible assets, net of amortization of $8,929 in 2007 and $4,676 in 2006	77,804	76,923
Long-term assets from risk management activities	-	1,674
Other, net of amortization of debt issuance costs of $2,488 in 2007 and $946 in 2006	13,529	17,212
Investments in unconsolidated investee	-	5,616
Goodwill	94,075	57,552
Total other assets	185,408	158,977
TOTAL ASSETS	$ 1,173,877	$ 1,013,085
LIABILITIES & PARTNERS' CAPITAL		
Current Liabilities:		
Accounts payable, accrued cost of gas and liquids and accrued liabilities	$ 138,933	$ 117,254
Related party payables	50	280
Escrow payable	6,029	5,783
Accrued taxes payable	3,593	2,758
Liabilities from risk management activities	37,852	3,647
Other current liabilities	5,123	5,592
Total current liabilities	191,580	135,314

Long-term liabilities from risk management activities		15,073		145
Other long-term liabilities		15,393		269
Long-term debt		481,500		664,700
Commitments and contingencies				
Partners' Capital:				
Common units (40,514,895 and 21,969,480 units authorized; 40,514,895 and 19,620,396 units issued and outstanding at December 31, 2007 and 2006, respectively)		490,351		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, 2007 and 2006)		7,019		43,240
General partner interest		11,286		5,543
Accumulated other comprehensive income (loss)		(38,325)		1,019
Total partners' capital		470,331		212,657
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$	1,173,877	$	1,013,085

See accompanying notes to consolidated financial statements

Table of Contents

Regency Energy Partners LP
Consolidated Statements of Operations
(in thousands except unit data and per unit data)

	Year Ended December 31, 2007	2006	2005
REVENUES			
Gas sales	$ 744,681	$ 560,620	$ 506,278
NGL sales	347,737	256,672	183,073
Gathering, transportation and other fees, including related party amounts of $1,350, $2,160, and $833	78,460	63,071	27,568
Net realized and unrealized loss from risk management activities	(34,266)	(7,709)	(22,243)
Other	31,442	24,211	14,725
Total revenues	1,168,054	896,865	709,401
OPERATING COSTS AND EXPENSES			
Cost of gas and liquids, including related party amounts of $14,165, $1,630, and $523	976,145	740,446	632,865
Operation and maintenance	45,474	39,496	24,291
General and administrative	39,543	22,826	15,039
Loss on asset sales, net	1,522	-	-
Management services termination fee	-	12,542	-
Transaction expenses	420	2,041	-
Depreciation and amortization	51,739	39,654	23,171
Total operating costs and expenses	1,114,843	857,005	695,366
OPERATING INCOME	53,211	39,860	14,035
Interest expense, net	(52,016)	(37,182)	(17,880)
Loss on debt refinancing	(21,200)	(10,761)	(8,480)
Other income and deductions, net	1,308	839	733
LOSS FROM CONTINUING OPERATIONS	(18,697)	(7,244)	(11,592)
DISCONTINUED OPERATIONS			
Income from operations of Regency Gas Treating LP (including gain on disposal of $626)	-	-	732
LOSS BEFORE INCOME TAXES	(18,697)	(7,244)	(10,860)
Income tax expense	931	-	-
NET LOSS	$ (19,628)	$ (7,244)	$ (10,860)
Less: Net income from January 1-31, 2006	-	1,564	
Net loss for partners	$ (19,628)	$ (8,808)	

General partner's interest		(393)		(176)
Beneficial conversion feature for Class C common units		1,385		3,587
Limited partners' interest	$	(20,620)	$	(12,219)
Basic and diluted earnings per unit:				
Amount allocated to common and subordinated units	$	(20,620)	$	(11,333)
Weighted average number of common and subordinated units outstanding		51,056,769		38,207,792
Loss per common and subordinated unit	$	(0.40)	$	(0.30)
Distributions declared per unit	$	1.52	$	0.9417
Amount allocated to Class B common units	$	-	$	(886)
Weighted average number of Class B common units outstanding		651,964		5,173,189
Loss per Class B common unit	$	-	$	(0.17)
Distributions declared per unit	$	-	$	-
Amount allocated to Class C common units	$	1,385	$	3,587
Total Class C common units outstanding		2,857,143		2,857,143
Income per Class C common unit due to beneficial conversion feature	$	0.48	$	1.26
Distributions declared per unit	$	-	$	-

See accompanying notes to consolidated financial statements

Table of Contents

Regency Energy Partners LP
Consolidated Statements of Comprehensive Income (Loss)
(in thousands)

	Year Ended December 31, 2007	2006	2005
Net loss	$ (19,628)	$ (7,244)	$ (10,860)
Hedging losses reclassified to earnings	19,362	1,815	5,540
Net change in fair value of cash flow hedges	(58,706)	10,166	(16,502)
Comprehensive income (loss)	$ (58,972)	$ 4,737	$ (21,822)

See accompanying notes to consolidated financial statements

Table of Contents

Regency Energy Partners LP
Consolidated Statements of Cash Flows
(in thousands)

	Year Ended December 31, 2007	2006	2005
OPERATING ACTIVITIES			
Net loss	$ (19,628)	$ (7,244)	$ (10,860)
Adjustments to reconcile net loss to net cash flows provided by operating activities:			
Depreciation and amortization	53,734	39,287	24,286
Write-off of debt issuance costs	5,078	10,761	8,480
Equity income	(43)	(532)	(312)
Risk management portfolio valuation changes	14,667	(2,262)	11,191
Loss (gain) on asset sales	1,522	-	(1,254)
Unit based compensation expenses	15,534	2,906	-
Cash flow changes in current assets and liabilities:			
Accrued revenues and accounts receivable	(30,608)	(5,506)	(43,012)
Other current assets	(1,293)	104	(2,644)
Accounts payable, accrued cost of gas and liquids and accrued liabilities	36,319	(1,359)	52,651
Accrued taxes payable	835	492	806
Other current liabilities	(984)	3,148	1,269
Proceeds from early termination of interest rate swap	-	4,940	-
Amount of swap termination proceeds reclassified into earnings	(1,078)	(3,862)	-
Other assets and liabilities	358	3,283	(3,261)
Net cash flows provided by operating activities	74,413	44,156	37,340
INVESTING ACTIVITIES			
Capital expenditures	(123,302)	(142,423)	(172,567)
Acquisition of Pueblo, net of $55 cash	(34,855)	-	-
Acquisition of Como assets	-	(81,695)	-
Acquisition of Enbridge assets	-	-	(108,282)
Acquisition of investment in unconsolidated investee, net of $100 cash	(5,000)	-	-
Cash outflows for acquisition by HM Capital Investors	-	-	(5,808)
Proceeds from asset sales	11,706	-	7,099
Other investing changes	-	468	(405)
Net cash flows used in investing activities	(151,451)	(223,650)	(279,963)
FINANCING ACTIVITIES			
Net borrowings under revolving credit facilities	59,300	14,700	50,000
Borrowings under credit facilities	-	599,650	60,000
Repayments under credit facilities	(50,000)	(858,600)	(1,650)
Borrowings under TexStar loan agreement	-	85,000	70,000
Repayments under TexStar loan agreement	-	(155,000)	-
Proceeds (repayments) of senior notes, net of debt issuance costs	(192,500)	536,175	-
Partner contributions	7,735	3,786	72,000

Partner distributions	(79,933)	(37,144)	-
Debt issuance costs and shelf registration fees	(2,427)	(10,488)	(6,201)
Proceeds from equity issuances, net of issuance costs	353,546	312,700	-
Cash distribution to HM Capital	-	(243,758)	-
Proceeds from exercise of over allotment option	-	26,163	-
Over allotment option proceeds to HM Capital	-	(26,163)	-
Acquisition of assets between entities under common control	-	(62,074)	(1,800)
Proceeds from promissory note to HMTF Gas Partners	-	-	600
Net cash flows provided by financing activities	95,721	184,947	242,949
Net increase in cash and cash equivalents	18,683	5,453	326
Cash and cash equivalents at beginning of period	9,139	3,686	3,360
Cash and cash equivalents at end of period	$ 27,822	$ 9,139	$ 3,686
Supplemental cash flow information			
Interest paid and early redemption penalty, net of amounts capitalized	$ 67,844	$ 33,347	$ 16,731
Non-cash capital expenditures in accounts payable	7,409	23,822	21,360
Non-cash capital expenditures for consolidation of investment in previously unconsolidated subsidiary	5,650	-	-
Non-cash capital expenditure upon entering into a capital lease obligation	3,000	-	-
Issuance of common units for acquisition	19,724	-	-

See accompanying notes to consolidated financial statements

Table of Contents

Regency Energy Partners LP
Consolidated Statements of Member Interest and Partners' Capital
(in thousands except unit data)

	Units								
	Common	Class B	Class C	Subordinated	Member Interest	Common Unitholders	Class B Unitholders	Class C Unitholders	Subord Unith
Balance - December 31, 2004	-	-	-	-	$ 181,936	$ -	$ -	$ -	$
Capital contributions	-	-	-	-	72,000	-	-	-	
Acquisition of fixed assets between entities under common control in excess of historical cost	-	-	-	-	(1,152)	-	-	-	
Net loss for the year ended December 31, 2005	-	-	-	-	(10,860)	-	-	-	
Net change in fair value of cash flow hedges	-	-	-	-	-	-	-	-	
Net hedging gain reclassified to earnings	-	-	-	-	-	-	-	-	
Balance - December 31, 2005	-	-	-	-	241,924	-	-	-	
Net income through January 31, 2006	-	-	-	-	1,564	-	-	-	
Net hedging loss reclassified to earnings	-	-	-	-	-	-	-	-	
Net change in fair value of cash flow hedges	-	-	-	-	-	-	-	-	
Balance - January 31, 2006	-	-	-	-	243,488	-	-	-	
	5,353,896	-	-	19,103,896	(182,320)	89,337	-	-	8

Contribution of net investment to unitholders									
Proceeds from initial public offering, net of issuance costs	13,750,000	-	-	-	-	125,907	-	-	12
Net proceeds from exercise of over allotment option	1,400,000	-	-	-	-	26,163	-	-	
Over allotment option net proceeds to HM Capital Investors	(1,400,000)	-	-	-	-	(26,163)	-	-	
Capital reimbursement to HM Capital Partners	-	-	-	-	-	(119,441)	-	-	(11
Offering costs	-	-	-	-	-	(2,056)	-	-	(
Issuance of Class B Common Units for TexStar member interest	-	5,173,189	-	-	(61,168)	-	61,168	-	
Payment to HM Capital for TexStar net of repayment of promissory note	-	-	-	-	-	(30,418)	-	-	(2
Other	-	-	-	-	-	(64)	(17)	(9)	
Issuance of Class C Common Units net of costs	-	-	2,857,143	-	-	-	-	59,942	
Issuance of restricted common units	516,500	-	-	-	-	-	-	-	
Unit based compensation expenses	-	-	-	-	-	1,339	146	59	
General Partner contributions			-	-	-	-	-	-	
Partner distributions	-	-	-	-	-	(18,409)	-	-	(1
Net loss from February 1 through December 31, 2006	-	-	-	-	-	(4,003)	(626)	-	(
	-	-	-	-	-	-	-	-	

Net hedging loss reclassified to earnings									
Net change in fair value of cash flow hedges	-	-	-	-	-	-	-	-	
Balance - December 31, 2006	19,620,396	5,173,189	2,857,143	19,103,896	-	42,192	60,671	59,992	4
Conversion of Class B and C to common units	8,030,332	(5,173,189)	(2,857,143)	-	-	120,663	(60,671)	(59,992)	
Issuance of common units for acquisition	751,597	-	-	-	-	19,724	-	-	
Issuance of common units	11,500,000	-	-	-	-	353,446	-	-	
Issuance of restricted common units	615,500	-	-	-	-	-	-	-	
Forfeitures of restricted common units	(50,333)	-	-	-	-	-	-	-	
Exercise of common unit options	47,403	-	-	-	-	100	-	-	
Unit based compensation expenses	-	-	-	-	-	15,534	-	-	
General Partner contributions	-	-	-	-	-	-	-	-	
Partner distributions	-	-	-	-	-	(49,296)	-	-	(2
Net loss	-	-	-	-	-	(12,037)	-	-	(
Other	-	-	-	-	-	25	-	-	
Net hedging activity reclassified to earnings	-	-	-	-	-	-	-	-	
Net change in fair value of cash flow hedges	-	-	-	-	-	-	-	-	
Balance - December 31, 2007	40,514,895	-	-	19,103,896	$ -	$ 490,351	$ -	$ -	$

See accompanying notes to consolidated financial statements

F-9

Table of Contents

Regency Energy Partners LP
Notes to Consolidated Financial Statements

1. Organization and Basis of Presentation

Organization. The consolidated financial statements presented herein contain the results of Regency Energy Partners LP ("Partnership"), a Delaware limited partnership, and its predecessor, Regency Gas Services LLC ("Predecessor"). The Partnership was formed on September 8, 2005; on February 3, 2006, in conjunction with its initial public offering of securities ("IPO"), the Predecessor was converted to a limited partnership Regency Gas Services LP ("RGS") and became a wholly owned subsidiary of the Partnership. The Partnership and its subsidiaries are engaged in the business of gathering, treating, processing, transporting, and marketing natural gas and natural gas liquids ("NGLs"). Regency GP LP is the Partnership's general partner and Regency GP LLC (collectively the "General Partner") is the managing general partner of the Partnership and the general partner of Regency GP LP.

On August 15, 2006, the Partnership acquired all the outstanding equity of TexStar Field Services, L.P. and its general partner, TexStar GP, LLC (collectively "TexStar"), from HMTF Gas Partners II, L.P. ("HMTF Gas Partners"), an affiliate of HM Capital Partners LLC ("HM Capital Partners") ("TexStar Acquisition"). Because the TexStar Acquisition was a transaction between commonly controlled entities, the Partnership accounted for the TexStar Acquisition in a manner similar to a pooling of interests. Information included in these financial statements is presented as if the Partnership and TexStar had been combined throughout the periods presented in which common control existed, December 1, 2004 forward.

On June 18, 2007, Regency GP Acquirer LP, an indirect subsidiary of GECC, acquired 91.3 percent of both the member interest in the General Partner and the outstanding limited partner interests in the General Partner from an affiliate of HM Capital Partners. Concurrently, Regency LP Acquirer LP, another indirect subsidiary of GECC, acquired 17,763,809 of the outstanding subordinated units, exclusive of 1,222,717 subordinated units which were owned directly or indirectly by certain members of the Partnership's management team. As a part of this acquisition, affiliates of HM Capital Partners entered into an agreement to hold 4,692,417 of the Partnership's common units for a period of 180 days. In addition, a separate affiliate of HM Capital Partners entered into an agreement to hold 3,406,099 of the Partnership's common units for a period of one year.

GE Energy Financial Services is a unit of GECC which is an indirect wholly owned subsidiary of GE. For simplicity, we refer to Regency GP Acquirer LP, Regency LP Acquirer LP and GE Energy Financial Services collectively as "GE EFS." Concurrent with the Partnership's issuance of common units in July and August 2007, GE EFS and certain members of the Partnership's management made a capital contribution aggregating to $7,735,000 to maintain the General Partner's two percent interest in the Partnership.

Concurrent with the GE EFS acquisition, eight members of the Partnership's senior management, together with two independent directors, entered into an agreement to sell an aggregate of 1,344,551 subordinated units for a total consideration of $24.00 per unit. Additionally, GE EFS entered into a subscription agreement with four officers and certain other management of the Partnership whereby these individuals acquired an 8.2 percent indirect economic interest in the General Partner.

The Partnership was not required to record any adjustments to reflect GE EFS's acquisition of the HM Capital Partners' interest in the Partnership or the related transactions (together, referred to as "GE EFS Acquisition").

Basis of Presentation. The consolidated financial statements of the Partnership have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") and include the accounts of all controlled subsidiaries after the elimination of all intercompany accounts and transactions. Certain prior year amounts have been reclassified to conform to current year’s presentation.

The accompanying consolidated financial statements include the assets, liabilities, results of operations and cash flows of the Partnership and its wholly owned subsidiaries. The Partnership operates and manages its business as two reportable segments: a) gathering and processing, and b) transportation as of December 31, 2007.

2. Summary of Significant Accounting Policies

Use of Estimates. These consolidated financial statements have been prepared in conformity with GAAP which necessarily include the use of estimates and assumptions by management that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities that exist at the date of the financial statements. 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.

Cash and Cash Equivalents. Cash and cash equivalents include temporary cash investments with original maturities of three months or less.

Restricted Cash. Restricted cash of $6,029,000 is held in escrow for environmental remediation projects pursuant to an escrow agreement. A third-party agent invests funds held in escrow in US Treasury securities. Interest earned on the investment is credited to the escrow account.

Table of Contents

Property, Plant and Equipment. Property, plant and equipment is recorded at historical cost of construction or, upon acquisition, the fair value of the assets acquired. Sales or retirements of assets, along with the related accumulated depreciation, are included in operating income unless the disposition is treated as discontinued operations. Gas to maintain pipeline minimum pressures is capitalized and classified as property, plant, and equipment. Financing costs associated with the construction of larger assets requiring ongoing efforts over a period of time are capitalized. For the year ended December 31, 2007, 2006, and 2005, the Partnership capitalized interest of $1,754,000, $511,000, and $2,613,000, respectively. The costs of maintenance and repairs, which are not significant improvements, are expensed when incurred. Expenditures to extend the useful lives of the assets are capitalized.

The Partnership assesses long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability is assessed by comparing the carrying amount of an asset to undiscounted future net cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured as the amount by which the carrying amounts exceed the fair value of the assets.

The Partnership accounts for its asset retirement obligations in accordance with Statement of Financial Accounting Standards ("SFAS") No. 143 "Accounting for Asset Retirement Obligations" and FIN 47 "Accounting for Conditional Asset Retirement Obligations." These accounting standards require the Partnership to recognize on its balance sheet the net present value of any legally binding obligation to remove or remediate the physical assets that it retires from service, as well as any similar obligations for which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Partnership. While the Partnership is obligated under contractual agreements to remove certain facilities upon their retirement, management is unable to reasonably determine the fair value of such asset retirement obligations because the settlement dates, or ranges thereof, were indeterminable and could range up to 95 years, and the undiscounted amounts are immaterial. An asset retirement obligation will be recorded in the periods wherein management can reasonably determine the settlement dates.

Depreciation expense related to property, plant and equipment was $47,384,000, $36,880,000, and $21,191,000 for the years ended December 31, 2007, 2006, and 2005, respectively. Depreciation of plant and equipment is recorded on a straight-line basis over the following estimated useful lives.

Functional Class of Property	Useful Lives (Years)
Gathering and Transmission Systems	5 - 20
Gas Plants and Buildings	15 - 35
Other property, plant and equipment	3 - 10

Intangible Assets. Intangible assets consisting of (i) permits and licenses and (ii) customer contracts are amortized on a straight line basis over their estimated useful lives, which is the period over which the assets are expected to contribute directly or indirectly to the Partnership's future cash flows. The value of the permits and licenses was determined by discounting the income associated with activities that would be lost over the period required to replace these permits and their estimated useful life is fifteen years. The Partnership renegotiated a number of significant customer contracts and the value of customer contracts was determined by using a discounted cash flow model. The estimated useful lives range from three to thirty years.

The Partnership evaluates the carrying value of intangible assets whenever certain events or changes in circumstances indicate that the carrying amount of these assets may not be recoverable. In assessing the recoverability, the Partnership compares the carrying value to the undiscounted future cash flows the intangible assets are expected to generate. If the total of the undiscounted future cash flows is less than the carrying amount of the intangible assets, the intangibles are written down to their fair value. The Partnership did not record any impairment in 2007, 2006, or

2005.

Goodwill. Goodwill represents the excess of the purchase price over the fair value of net assets acquired in a business combination. Goodwill is allocated to two reportable segments, Gathering and Processing and Transportation. Goodwill is not amortized, but is tested for impairment annually based on the carrying values as of December 31, or more frequently if impairment indicators arise that suggest the carrying value of goodwill may not be recovered. Impairment occurs when the carrying amount of a reporting unit exceeds it fair value. At the time it is determined that an impairment has occurred, the carrying value of the goodwill is written down to its fair value. To estimate the fair value of the reporting units, the Partnership makes estimates and judgments about future cash flows, as well as to revenues, cost of sales, operating expenses, capital expenditures and net working capital based on assumptions that are consistent with the Partnership's most recent forecast. No impairment was indicated for the years ended December 31, 2007, 2006 or 2005.

Investment in Unconsolidated Investee. Investments in entities for which the Partnership has significant influence over the investee's operating and financial policies, but less than a controlling interest, are accounted for using the equity method. Under the equity method, the Partnership's investment in an investee is included in the consolidated balance sheets under the caption investments in unconsolidated investee and the Partnership's share of the investee's earnings or loss is included in the consolidated statements of operations under the caption other income and deductions, net. All of the Partnership's investments are subject to periodic impairment review. The impairment analysis requires significant judgment to identify events or circumstances that would likely have significant adverse effect on the future use of the investment. The Partnership purchased the remaining minority interest in its sole unconsolidated investee in February 2007.

Table of Contents

Other Assets, net. Other assets, net primarily consists of debt issuance costs, which are capitalized and amortized to interest expense, net over the life of the related debt.

Gas Imbalances. Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements are recorded monthly as other current assets or other current liabilities using then current market prices or the weighted average prices of natural gas or NGLs at the plant or system pursuant to imbalance agreements for which settlement prices are not contractually established. Within certain volumetric limits determined at the sole discretion of the creditor, these imbalances are generally settled by deliveries of natural gas. Imbalance receivables and payables as of December 31, 2007 and 2006 were immaterial.

Revenue Recognition. The Partnership earns revenues from (i) domestic sales of natural gas, NGLs and condensate and (ii) natural gas gathering, processing and transportation. Revenues associated with sales of natural gas, NGLs and condensate are recognized when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery occurs. Revenues associated with transportation and processing fees are recognized when the service is provided. For gathering and processing services, the Partnership receives either fees or commodities from natural gas producers depending on the type of contract. Commodities received are in turn sold and recognized as revenue in accordance with the criteria outlined above. Under the percentage-of-proceeds contract type, the Partnership is paid for its services by keeping a percentage of the NGLs produced and a percentage of the residue gas resulting from processing the natural gas. Under the percentage-of-index contract type, the Partnership earns revenue by purchasing wellhead natural gas at a percentage of the index price and selling processed natural gas at a price approximating the index price and NGLs to third parties. The Partnership generally reports revenues gross in the consolidated statements of operations, in accordance with EITF Issue No. 99-19, “Reporting Revenue Gross as a Principal versus Net as an Agent.” Except for fee-based agreements, the Partnership acts as the principal in these transactions, takes title to the product, and incurs the risks and rewards of ownership.

Risk Management Activities. The Partnership’s net income and cash flows are subject to volatility stemming from changes in market prices such as natural gas prices, natural gas liquids prices, and processing margins. The Partnership uses ethane, propane, butane, natural gasoline, and condensate swaps to create offsetting positions to specific commodity rate exposures. Prior to July 1, 2005, derivative financial instruments were not designated for hedge accounting and the changes in fair value of these contracts were marked to market and unrealized gains and losses were recorded in revenue. Subsequent to July 1, 2005, the Partnership accounts for derivative financial instruments in accordance with SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities”, as amended (“SFAS No. 133”), whereby all derivative financial instruments were recorded in the balance sheet at their fair value on a net basis by settlement date. The Partnership employs derivative financial instruments in connection with an underlying asset, liability and/or anticipated transaction and not for speculative purposes. Derivative financial instruments qualifying for hedge accounting treatment have been designated by the Partnership as cash flow hedges. The Partnership enters into cash flow hedges to hedge the variability in cash flows related to a forecasted transaction.

At inception, the Partnership formally documents the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing correlation and hedge effectiveness. The Partnership also assesses, both at the inception of the hedge and on an on-going basis, whether the derivatives are highly effective in offsetting changes in cash flows of the hedged item. Furthermore, the Partnership regularly assesses the creditworthiness of counterparties to manage against the risk of default. If the Partnership determines that a derivative is no longer highly effective as a hedge, it discontinues hedge accounting prospectively by including changes in the fair value of the derivative in current earnings. For cash flow hedges, changes in the derivative fair values, to the extent that the hedges are effective, are recorded as a component of accumulated other comprehensive income until the hedged transactions occur and are recognized in earnings. Any ineffective portion of a cash flow hedge’s change in value is recognized immediately in earnings. In the statement of cash flows, the effects of settlements of derivative instruments are classified consistent with the related hedged transactions. For the Partnership's derivative financial instruments that were not designated for hedge accounting, the change in market value is recorded as a component of net unrealized and realized loss from risk management activities in the consolidated statements of operations.

Benefits. The Partnership provides a portion of medical, dental, and other healthcare benefits to employees. Commencing on June 1, 2005, the Partnership provides a matching contribution for employee contributions to their 401(k) accounts, which vests immediately. The amount of matching contributions for the years ended December 31, 2007, 2006, and 2005 was $469,000, $201,000, and $100,000, respectively, and is recorded in general and administrative expenses. The Partnership has no pension obligations or other post employment benefits.

Income Taxes. The Partnership is generally not subject to income taxes, except as discussed below, because its income is taxed directly to its partners. Effective January 1, 2007, the Partnership became subject to the gross margin tax enacted by the state of Texas on May 1, 2006. The Partnership has wholly-owned subsidiaries that are subject to income tax and provides for deferred income taxes using the asset and liability method for these entities. Accordingly, deferred taxes are recorded for differences between the tax and book basis that will reverse in future periods. The Partnership's deferred tax liability of $8,642,000 as of December 31, 2007 relates to the difference between the book and tax basis of property, plant, and equipment and intangible assets and is included in other long-term liabilities in the accompanying consolidated balance sheet. The Partnership adopted the provisions of FIN No. 48 "Accounting for Uncertainty in Income Taxes — An Interpretation of FASB Statement 109", on January 1, 2007. Upon adoption, the Partnership did not identify or record any uncertain tax positions not meeting the more likely than not standard. The Partnership's entities that are required to pay federal income tax recognized current income tax expense ($1,171,000) and deferred income tax benefit ($240,000) using a 35.325 percent effective rate.

Table of Contents

Equity-Based Compensation. The Partnership adopted SFAS 123(R) "Share-Based Payment" in the first quarter of 2006 upon the creation of the long-term incentive plan ("LTIP"). The adoption had no impact on the consolidated financial position, result of operations or cash flows as no LTIP awards were granted prior to adoption.

Earnings per unit. Earnings per unit information has not been presented for periods prior to the IPO. Basic net income per limited partner unit is computed in accordance with SFAS No. 128, "Earnings Per Share", as interpreted by Emerging Issues Task Force ("EITF") Issue No. 03-6 ("EITF 03-6"), "Participating Securities and the Two-Class method under FASB Statement No. 128." After deducting the general partners' interest in net income or loss which may consist of its 2 percent interest, made whole for any losses allocated in a prior year or incentive distribution rights, the limited partners' interest in the remaining net income or loss is allocated to each class of equity units based on declared distributions and then divided by the weighted average number of units outstanding in each class of security. In periods when the Partnership's aggregate net income exceeds the aggregate distributions, EITF 03-6 requires the Partnership to present earnings per unit as if all of the earnings for the periods were distributed. Diluted net income per limited partner unit is computed by dividing limited partners' interest in net income, after deducting the general partner's interest, by the weighted average number of common and subordinated units outstanding and the effect of nonvested restricted units and unit options computed using the treasury stock method. Common and subordinated units are considered to be a single class.

Recently Issued Accounting Standards. In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" ("SFAS No. 157"), 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 No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years, except for non-financial assets and non-financial liabilities that are recognized or disclosed at fair value in the financial statements on a recurring basis when the effective date is fiscal years beginning after November 15, 2008. Disclosures under SFAS 157 were not deferred. The Partnership is currently evaluating the potential impacts on its financial position, results of operations or cash flows of the adoption of this standard.

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. The Partnership is currently evaluating the potential impacts on its financial position, results of operations or cash flows of the adoption of this standard.

On December 4, 2007, the FASB issued SFAS No. 141R, "Business Combinations" ("SFAS No. 141R"), which significantly changes the accounting for business acquisitions both during the period of the acquisition and in subsequent periods. SFAS No. 141R is effective for fiscal years beginning after December 15, 2008. The Partnership is currently evaluating the potential impacts on its financial position, results of operations or cash flows of the adoption of this standard.

On December 4, 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51" ("SFAS No. 160"), which will significantly change the accounting and reporting related to noncontrolling interests in a consolidated subsidiary. SFAS No. 160 is effective for fiscal years beginning after December 15, 2008. The Partnership is currently evaluating the potential impacts on its financial position, results of operations or cash flows of the adoption of this standard.

3. Partners' Capital and Distributions

Initial Public Offering. On February 3, 2006, the Partnership offered and sold 13,750,000 common units, representing a 35.3 percent limited partner interest in the Partnership, in its IPO, at a price of $20.00 per unit. Total proceeds from the sale of the units were $275,000,000, before offering costs and underwriting commissions. On March 8, 2006, the Partnership sold an additional 1,400,000 common units at a price of $20.00 per unit as the underwriters exercised a portion of their over allotment option.

Class B Common Units. On August 15, 2006, in connection with the TexStar Acquisition, the Partnership issued 5,173,189 of Class B common units to HMTF Gas Partners as partial consideration for the TexStar Acquisition. The Class B common units had the same terms and conditions as the Partnership's common units, except that the Class B common units were not entitled to participate in earnings or 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.

Class C Common Units. On September 21, 2006, the Partnership entered into a Class C Unit Purchase Agreement with certain purchasers, pursuant to which the purchasers purchased 2,857,143 Class C common units representing limited partner interests in the Partnership at a price of $21.00 per unit. The Class C common units had the same terms and conditions as the Partnership's common units, except that the Class C common units were not entitled to participate in earnings or 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.

Table of Contents

2007 Equity Offering. On July 26, 2007, the Partnership sold 10,000,000 common units for $32.05 per unit. After deducting underwriting discounts and commissions of $12,820,000, the Partnership received $307,680,000 from this sale, excluding the general partner's proportionate capital contribution of $6,279,000 and offering expenses of $386,000. On July 31, 2007, the Partnership sold an additional 1,500,000 for $32.05 as the underwriters exercised their option to purchase additional units. The Partnership received $46,152,000 from this sale after deducting underwriting discounts and commissions and excluding the general partner's proportionate capital contribution of $942,000. The Partnership used a portion of these proceeds to repay amounts outstanding under the term ($50,000,000) and revolving credit facility ($178,930,000). With the remaining proceeds and additional borrowings under the revolving credit facility, the Partnership repurchased $192,500,000, or 35 percent, of its outstanding senior notes which required the Partnership to pay an early redemption penalty of $16,122,000 in August 2007.

Distributions. Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of the Partnership's Available Cash (defined below) to unitholders of record on the applicable record date, as determined by the general partner.

Available Cash. Available Cash, for any quarter, generally consists of all cash and cash equivalents on hand at the end of that quarter less the amount of cash reserves established by the general partner to: (i) provide for the proper conduct of the Partnership's business; (ii) comply with applicable law, any debt instruments or other agreements; or (iii) provide funds for distributions to the unitholders and to the general partner for any one or more of the next four quarters and plus, all cash on hand on that date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter for which the determination is being made.

General Partner Interest and Incentive Distribution Rights. The general partner is entitled to 2 percent of all quarterly distributions that the Partnership makes prior to its liquidation. This general partner interest is represented by 1,216,710 equivalent units as of December 31, 2007. The general partner has the right, but not the obligation, to contribute a proportionate amount of capital to the Partnership to maintain its current general partner interest. The general partner's initial 2 percent interest in these distributions will be reduced if the Partnership issues additional units in the future and the general partner does not contribute a proportionate amount of capital to the Partnership to maintain its 2 percent general partner interest.

The incentive distribution rights held by the general partner entitles it to receive an increasing share of Available Cash when pre-defined distribution targets are achieved. The general partner's incentive distribution rights are not reduced if the Partnership issues additional units in the future and the general partner does not contribute a proportionate amount of capital to the Partnership to maintain its 2 percent general partner interest. Please read the Distributions of Available Cash during the Subordination Period and Distributions of Available Cash after the Subordination Period sections below for more details about the distribution targets and their impact on the general partner's incentive distribution rights.

Subordinated Units. All of the subordinated units are held by GE EFS and members of senior management. The partnership agreement provides that, during the subordination period, the common units will have the right to receive distributions of Available Cash each quarter in an amount equal to $0.35 per common unit, or the "Minimum Quarterly Distribution," plus any arrearages in the payment of the Minimum Quarterly Distribution on the common units from prior quarters, before any distributions of Available Cash may be made on the subordinated units. These units are deemed "subordinated" because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received the Minimum Quarterly Distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The practical effect of the subordinated units is to increase the likelihood that during the subordination period there will be Available Cash to be distributed on the common units. The subordination period will end, and the subordinated units will convert to common units, on a one for one basis, when certain distribution requirements, as defined in the partnership agreement, have been met. The earliest date at which the subordination period may end is December 31, 2008. The rights of the subordinated unitholders, other than the distribution rights described above, are substantially the same as the rights of the common unitholders.

Distributions of Available Cash during the Subordination Period. The partnership agreement requires that we make distributions of Available Cash for any quarter during the subordination period in the following manner:

- § first, 98 percent to the common unitholders, pro rata, and 2 percent to the general partner, until we distribute for each outstanding common unit an amount equal to the Minimum Quarterly Distribution for that quarter;
- § second, 98 percent to the common unitholders, pro rata, and 2 percent to the general partner, until we distribute for each

Table of Contents

- § outstanding common unit an amount equal to any arrearages in payment of the Minimum Quarterly Distribution on the common units for any prior quarters during the subordination period;
- § third, 98 percent to the subordinated unitholders, pro rata, and 2 percent to the general partner, until we distribute for each subordinated unit an amount equal to the Minimum Quarterly Distribution for that quarter;
- § fourth, 98 percent to all unitholders, pro rata, and 2 percent to the general partner, until each unitholder receives a total of $0.4025 per unit for that quarter;
- § fifth, 85 percent to all unitholders, pro rata, and 15 percent to the general partner, until each unitholder receives a total of $0.4375 per unit for that quarter;
- § sixth, 75 percent to all unitholders, pro rata, and 25 percent to the general partner, until each unitholder receives a total of $0.525 per unit for that quarter; and
- § thereafter, 50 percent to all unitholders, pro rata, and 50 percent to the general partner.

Distributions of Available Cash after the Subordination Period. The Partnership Agreement requires that we make distributions of Available Cash from operating surplus for any quarter after the subordination period in the following manner:

- § first, 98 percent to all unitholders, pro rata, and 2 percent to the general partner, until each unitholder receives a total of $0.4025 per unit for that quarter;
- § second, 85 percent to all unitholders, pro rata, and 15 percent to the general partner, until each unitholder receives a total of $0.4375 per unit for that quarter;
- § third, 75 percent to all unitholders, pro rata, and 25 percent to the general partner, until each unitholder receives a total of $0.525 per unit for that quarter; and
- § thereafter, 50 percent to all unitholders, pro rata, and 50 percent to the general partner.

Distributions. The Partnership made the following cash distributions during the years ended December 31, 2007 and 2006:

Distribution Date	Cash Distributions (per unit)
2006	
May 15, 2006	$ 0.2217
August 14, 2006	0.3500
November 14, 2006	0.3700
2007	
February 14, 2007	0.3700
May 15, 2007	0.3800
August 14, 2007	0.3800
November 14, 2007	0.3900

4. Loss per Limited Partner Unit

Loss per unit for the year ended December 31, 2006 reflects only the eleven months since the closing of the Partnership's IPO on February 3, 2006. For convenience, January 31, 2006 has been used as the date of the change in ownership. Accordingly, results for January 2006 have been excluded from the calculation of loss per unit. While the non-vested (or restricted) units are deemed to be outstanding for legal purposes, they have been excluded from the calculation of basic loss per unit in accordance with SFAS No. 128.

The following data show the number of potential dilutive common units that were excluded from the loss per unit calculation.

	December 31, 2007	December 31, 2006
Restricted common units	397,500	516,500
Common unit options	738,668	909,600

Restricted common units generally vest at the rate of one-fourth of the total grant per year. A significant portion of the restricted units outstanding at December 31, 2007 were granted on June 18, 2007 upon the acquisition by GE EFS of a controlling interest in the Partnership. All of the restricted units outstanding at December 31, 2006 that remained outstanding at the time of the GE EFS Acquisition vested upon the change in control of the Partnership, converting to common units on a one-to-one basis.

Subsequent to the GE EFS Acquisition, the outstanding common unit options immediately vested. These options generally expire ten years after the grant date. The options were granted with a strike price equal to the grant date closing price of the Partnership's common units. As of December 31, 2007, the Partnership had not granted any new options following the GE EFS Acquisition.

In accordance with SFAS No. 128, the Partnership allocates net income or loss to each class of equity security in proportion to the amount of income earned during that period after deducting distributions. Because the Class B common units used in the TexStar Acquisition were deemed to be outstanding for all periods presented, a portion of net income or loss was allocated to this class of equity in periods where they were not expressly prohibited from receiving distributions. The Partnership issued Class D and Class E common units in January 2008 and these securities are described in the subsequent events footnote.

Table of Contents

The Partnership Agreement requires that the general partner shall receive a 100 percent allocation of income until its capital account is made whole for all of the net losses allocated to it in prior years.

Subsequent to the issuance of its consolidated financial statements for the year ended December 31, 2006, the Partnership identified an error in the calculation of earnings per unit resulting from the issuance of Class C common units at a discount. At the commitment date to sell the Class C common units the purchase price of $21.00 per unit represented a $1.74 discount from the fair value of the Partnership's common units. Under EITF No. 98-5, "Accounting for Convertible Securities with Beneficial Conversion Features or Contingently Adjustable Conversion Ratios," the discount represented a beneficial conversion feature ("BCF") that should have been treated as a non-cash distribution for purposes of calculating earnings per unit. The BCF is reflected in loss per unit using the effective yield method over the period the Class C common units are outstanding, as indicated on the statements of operations in the line item entitled "beneficial conversion feature for Class C common units" for the years ended December 31, 2007 and 2006. The error is immaterial and had no impact on the Partnership's net loss or partners' capital.

The following table depicts the effect on earnings per unit for the year ended December 31, 2006.

		As Previously Reported		As Restated
		(in thousands, except for earnings per unit and units)		
NET LOSS	$	(7,244)	$	(7,244)
Less: Net income from January 1-31, 2006		1,564		1,564
Net loss for partners		(8,808)		(8,808)
General partner's interest		(176)		(176)
Beneficial conversion feature for Class C common units		-		3,587
Limited partners' interest	$	(8,632)	$	(12,219)
Basic and diluted earnings per unit:				
Amount allocated to common and subordinated units	$	(8,006)	$	(11,333)
Weighted average number of common and subordinated units outstanding		38,207,792		38,207,792
Loss per common and subordinated unit	$	(0.21)	$	(0.30)
Distributions declared per unit	$	0.94	$	0.94
Amount allocated to Class B common units	$	(626)	$	(886)
Weighted average number of Class B common units outstanding		5,173,189		5,173,189
Loss per Class B common unit	$	(0.12)	$	(0.17)
Distributions declared per unit	$	-	$	-
Amount allocated to Class C common units	$	-	$	3,587
Total Class C common units outstanding		871,817		2,857,143
Income per Class C common unit due to beneficial conversion feature	$	-	$	1.26
Distributions declared per unit	$	-	$	-

5. Acquisitions and Dispositions

2007

Palafox Joint Venture. The Partnership acquired the outstanding interest in the Palafox Joint Venture not owned (50 percent) for $5,000,000 effective February 1, 2007. The Partnership allocated $10,057,000 to gathering and transmission systems in the three months ended March 31, 2007. The allocated amount consists of the investment in unconsolidated subsidiary of $5,650,000 immediately prior to the Partnership's acquisition and the Partnership's $5,000,000 purchase of the remaining interest offset by $593,000 of working capital accounts acquired.

Significant Asset Dispositions. The Partnership sold selected non-core pipelines, related rights of way and contracts located in south Texas for $5,340,000 on March 31, 2007 and recorded a loss on sale of $1,808,000. Additionally, the Partnership sold two small gathering systems and associated contracts located in the Midcontinent region for $1,750,000 on May 31, 2007 and recorded a loss on the sale of $469,000. The Partnership also sold its 34 mile NGL pipeline located in east Texas for $3,000,000 on June 29, 2007 and simultaneously entered into transportation and operating agreements with the buyer. The Partnership accounted for this transaction as a sale-leaseback whereby the $3,000,000 gain was deferred and will be amortized to earnings over a twenty year period. The Partnership recorded $3,000,000 in gathering and transmission systems and the related obligations under capital lease. On August 31, 2007, the Partnership sold an idle processing plant for $1,300,000 and recorded a $740,000 gain.

Table of Contents

Acquisition of Pueblo Midstream Gas Corporation. On April 2, 2007, the Partnership and its indirect wholly-owned subsidiary, Pueblo Holdings, Inc., a Delaware corporation ("Pueblo Holdings"), entered into a definitive Stock Purchase Agreement (the "Stock Purchase Agreement") with Bear Cub Investments, LLC, a Colorado limited liability company, the members of that company (the "Members") and Robert J. Clark, as Sellers' Representative, pursuant to which the Partnership and Pueblo Holdings on that date acquired all the outstanding equity of Pueblo Midstream Gas Corporation, a Texas corporation ("Pueblo"), from the Members (the "Pueblo Acquisition"). Pueblo owned and operated natural gas gathering, treating and processing assets located in south Texas. These assets are comprised of a 75 MMcf/d gas processing and treating facility, 33 miles of gathering pipelines and approximately 6,000 horsepower of compression.

The purchase price for the Pueblo Acquisition consisted of (1) the issuance of 751,597 common units of the Partnership to the Members, valued at $19,724,000 and (2) the payment of $34,855,000 in cash, exclusive of outstanding Pueblo liabilities of $9,822,000 and certain working capital amounts acquired of $108,000. The cash portion of the consideration was financed out of the proceeds of the Partnership's revolving credit facility.

The Pueblo Acquisition offers the opportunity to reroute gas to one of the Partnership's existing gas processing plants which is expected to provide cost savings. The total purchase price was allocated preliminarily as follows based on estimates of the fair values of assets acquired and liabilities assumed.

	At April 2, 2007 (in thousands)
Current assets	$ 1,295
Gas plants and buildings	8,994
Gathering and transmission systems	13,079
Other property, plant and equipment	180
Intangible assets subject to amortization (contracts)	5,242
Goodwill	36,523
Total assets acquired	$ 65,313
Current liabilities	(1,187)
Long-term liabilities	(9,492)
Total purchase price	$ 54,634

2006

TexStar. On August 15, 2006, the Partnership acquired all the outstanding equity of TexStar by issuing 5,173,189 Class B common units valued at $119,183,000, a cash payment of $62,074,000 and the assumption of $167,652,000 of TexStar's outstanding bank debt. Because the TexStar Acquisition is a transaction between commonly controlled entities, the Partnership accounted for the TexStar 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 from the date common control began (December 1, 2004) forward.

The following table presents the revenues and net income for the previously separate entities and the combined amounts presented in these audited consolidated financial statements.

	Year Ended December 31, 2006	2005
	(in thousands)	
Revenues		
Regency Energy Partners	$ 812,564	$ 692,603

TexStar Field Services	84,301	16,798
Combined	896,865	709,401
Net income (loss)		
Regency Energy Partners	(1,639)	(11,224)
TexStar Field Services	(5,605)	364
Combined	$ (7,244)	$ (10,860)

Como — On July 25, 2006, TexStar consummated an Asset Purchase and Sale Agreement (the "Como Acquisition Agreement") dated June 16, 2006 with Valence Midstream, Ltd. and EEC Midstream, Ltd., under which TexStar acquired certain natural gas gathering, treating and processing assets from the other parties thereto for $81,695,000 including transaction costs. The assets acquired consisted of approximately 59 miles of pipelines and certain specified contracts (the "Como Assets"). The results of operations of the Como Assets have been included in the statements of operations beginning July 26, 2006. The Partnership's purchase price allocation resulted in $18,493,000 being allocated to property, plant and equipment and $63,202,000 being allocated to intangible assets.

2005

Enbridge. TexStar acquired two sulfur recovery plants, one NGL plant and 758 miles of pipelines in east and south Texas (the "Enbridge Assets") from Enbridge Pipelines (NE Texas), LP, Enbridge Pipeline (Texas Intrastate), LP and Enbridge Pipelines (Texas Gathering), LP (collectively "Enbridge") for $108,282,000 inclusive of transaction expenses on December 7, 2005 (the "Enbridge

Table of Contents

Acquisition”). The Enbridge Acquisition was accounted for using the purchase method of accounting. For convenience, the results of operations of the Enbridge Assets are included in the 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.

Other 2005 Acquisitions. The Partnership made several other asset acquisitions during the year ended December 31, 2005. These individually immaterial acquisitions, when aggregated, are not material to the financial position or results of operations of the Partnership.

Regency Gas Treating LP. On May 2, 2005, the Partnership sold the assets of Regency Gas Treating LP for $6,000,000. After the allocation of $977,000 of goodwill, the resulting gain was $626,000. The Partnership treated this sale as a discontinued operation. The equipment lease revenue, operating income, and net income for the year ended December 31, 2005 was $335,000, $186,000, and $732,000, respectively.

The following unaudited pro forma financial information has been prepared for Pueblo, Como and Enbridge. The pro forma amounts include certain adjustments to historical results of operations including depreciation and amortization expense (based upon the estimated fair values and useful lives of property, plant and equipment). Such unaudited pro forma information does not purport to be indicative of the results of operations that would have been achieved if the transactions to which the Partnership is giving pro forma effect actually occurred on the date referred to above or the results of operations that may be expected in the future.

	Pro Forma Year Ended December 31,		
	2007	2006	2005
	(in thousands except unit and per unit data)		
Revenues	$ 1,171,775	$ 952,229	$ 836,809
Net loss	(19,319)	(6,876)	(10,784)
Less net income from January 1-31, 2006	-	1,564	
Net loss for partners	(19,319)	(8,440)	
General partner's equity ownership	(386)	(169)	
Beneficial conversion feature for Class C common units	1,385	3,587	
Limited partners' interest in net loss	$ (20,318)	$ (11,858)	
Net loss allocated to common and subordinated units	$ (20,318)	$ (10,999)	
Weighted average common and subordinated units – basic and diluted	51,056,769	38,207,792	
Loss per common units - basic and diluted	$ (0.40)	$ (0.29)	
Distributions declared per unit	$ 1.52	$ 0.9417	
Net loss allocated to Class B common units	$ -	$ (859)	
Weighted average Class B common units outstanding	651,964	5,173,189	
Loss per Class B common units - basic and diluted	$ -	$ (0.17)	
Distributions declared per unit	$ -	$ -	
Net loss allocated to Class C units	$ 1,385	$ 3,587	
Weighted average Class C common units outstanding	2,857,143	2,857,143	

Income per Class C common unit due to beneficial conversion feature	$	0.48	$	1.26
Distributions declared per unit	$	-	$	-

6. Risk Management Activities

Effective June 19, 2007, the Partnership elected to account for our entire outstanding commodity hedging instruments on a mark-to-market basis except for the portion of commodity hedging instruments where all NGLs products for a particular year were hedged and the hedging relationship was effective. As a result, a portion of commodity hedging instruments is and will continue to be accounted for using mark-to-market accounting until all NGLs products are hedged for an individual year and the hedging relationship is deemed effective. During the year ended December 31, 2007, the Partnership recorded $14,559,000 of mark-to-market losses for certain hedges that do not qualify for hedge accounting.

The Partnership's hedging positions reduce exposure to variability of future commodity prices through 2009. The net fair value of the Partnership's risk management activities constituted a net liability and a net asset of $52,925,000 and $8,000 as of December 31, 2007 and 2006, respectively. The Partnership expects to reclassify $36,171,000 of hedging losses as an offset to revenues from accumulated other comprehensive income (loss) in the next twelve months. The Partnership recognized immaterial gains related to hedged forecasted transactions that did not occur by the end of the originally specified period and recognized $486,000 of ineffectiveness during the year ended December 31, 2007.

Table of Contents

Upon the early termination of an interest rate swap with a notional debt amount of $200,000,000 that was effective from April 2007 through March 2009, the Partnership received $3,550,000 in cash from the counterparty. The Partnership reclassified $1,078,000 and $2,663,000 from accumulated other comprehensive income (loss), reducing interest expense, net in the years ended December 31, 2007 and 2006,respectively, because the hedged forecasted transaction will not occur.

Prior to the election of hedge accounting on July 1, 2005, realized and unrealized losses of $16,226,000 were recorded as a charge against revenue.

7. Long-term Debt

Obligations in the form of senior notes, and borrowings under the credit facilities are as follows.

	December 31, 2007 (in thousands)	December 31, 2006
Senior notes	$ 357,500	$ 550,000
Term loans	-	50,000
Revolving loans	124,000	64,700
Total	481,500	664,700
Less: current portion	-	-
Long-term debt	$ 481,500	$ 664,700
Availability under term and revolving credit facility		
Total credit facility limit	$ 500,000	$ 300,000
Term loans	-	(50,000)
Revolver loans	(124,000)	(64,700)
Letters of credit	(27,263)	(5,183)
Total available	$ 348,737	$ 180,117

Long-term debt maturities as of December 31, 2007 for each of the next five years are as follows.

Year ending December 31,	Amount (in thousands)
2008	$ -
2009	-
2010	-
2011	124,000
2012	-
Thereafter	357,500
Total	481,500

The Partnership borrowed and repaid $238,230,000 and $421,430,000, respectively, in the year ended December 31, 2007 under the revolving credit facility. The borrowings were made primarily to fund capital expenditures and proceeds from the equity offering were used to repay amounts outstanding under the revolving credit facility. During the year ended December 31, 2006 the Partnership borrowed $195,300,000 under the revolving credit facility, primarily to fund capital expenditures and temporarily finance the TexStar Acquisition. During the same period, it repaid $180,600,000 of these borrowings with the proceeds from term loans and private equity offering proceeds.

Senior Notes. In 2006, The Partnership and Regency Energy Finance Corp. (“Finance Corp”), a wholly-owned subsidiary of RGS, issued $550,000,000 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. In August 2007, the Partnership exercised its option to redeem 35 percent or $192,500,000 of its outstanding senior notes on or before December 15, 2009. Under the senior notes terms, no further redemptions are permitted until December 15, 2010. The Partnership made the redemption at a price of 108.375 percent of the principal amount plus accrued interest. Accordingly, a redemption premium of $16,122,000 was recorded as loss on debt refinancing and unamortized loan origination costs of $4,575,000 were written off and charged to loss on debt refinancing in the year ended December 31, 2007. A portion of the proceeds of an equity offering was used to redeem the senior notes. In September 2007, the Partnership exchanged its then outstanding 8 3/8 percent senior notes which were not registered under the Securities Act of 1933 for senior notes with identical terms that have been so registered.

The senior notes and the guarantees are unsecured and rank equally with all of the Partnership’s and the guarantors’ existing and future unsubordinated obligations. The senior notes and the guarantees will be senior in right of payment to any of the Partnership’s 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 the Partnership’s and the guarantors’ secured obligations, including the Partnership’s Credit Facility, to the extent of the value of the assets securing such obligations.

Table of Contents

The senior 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.

The Partnership 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, the Partnership 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.

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. The Partnership's ability to purchase the notes upon a change of control will be limited by the terms of the Partnership's debt agreements, including the Credit Facility. Subsequent to the GE EFS Acquisition, no bond holder has exercised this option.

The senior notes contain covenants that, among other things, limit the Partnership's ability and the ability of certain of the Partnership's 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 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, the Partnership and its restricted subsidiaries will no longer be subject to many of the foregoing covenants.

Finance Corp. has no operations and will not have revenue other than as may be incidental as a co-issuer of the senior notes. Since the Partnership has no independent operations, the guarantees are full and unconditional and joint and several and there are no subsidiaries of the Partnership that do not guarantee the senior notes, the Partnership has not included condensed consolidated financial information of guarantors of the senior notes.

Fourth Amended and Restated Credit Agreement. At December 31, 2006, RGS' Fourth Amended and Restated Credit Agreement ("Credit Facility") allowed for borrowings of $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 had 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 in commitments have been met. On September 28, 2007, the Partnership amended its Credit Facility, increasing the revolving debt commitment to $500,000,000. The Partnership retained its option to increase the commitment under the revolving or term credit facilities by an aggregate amount up to $250,000,000, subject to the same conditions noted above.

RGS' obligations under the Credit Facility are secured by substantially all of the assets of RGS and its subsidiaries and are guaranteed, except for those owned by one of our subsidiaries, by the Partnership and each such subsidiary. The revolving loans mature in five years.

Interest on revolving loans thereunder will be calculated, at the option of RGS, at either: (a) a base rate plus an applicable margin of 0.50 percent per annum or (b) an adjusted LIBOR rate plus an applicable margin of 1.50 percent per annum. 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 8.78 percent, 7.70 percent, and 6.57 percent for the years ended December 31, 2007, 2006, and 2005.

RGS must pay (i) a commitment fee equal to 0.30 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 1.50 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 EBITDA and EBITDA to interest expense within certain threshold ratios. At December 31, 2007, 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 the Partnership for expenses and payment of dividends to the Partnership to the extent of the Partnership's determination of available cash (so long as no default or event of default has occurred or is continuing). The Credit Facility also contains various covenants that limit (subject to certain exceptions and negotiated baskets), among other things, the ability of RGS (but not the Partnership):

§ to incur indebtedness;

§ to grant liens;

Table of Contents

- § to enter into sale and leaseback transactions;
- § to make certain investments, loans and advances;
- § to dissolve or enter into a merger or consolidation;
- § to enter into asset sales or make acquisitions;
- § to enter into transactions with affiliates;
- § to prepay other indebtedness or amend organizational documents or transaction documents (as defined in the Credit Facility);
- § to issue capital stock or create subsidiaries; or
- § to engage in any business other than those businesses in which it was engaged at the time of the effectiveness of the Credit Facility or reasonable extensions thereof.

The Partnership treated the amendment of the Credit Facility as an extinguishment and reissuance of debt, and therefore recorded a charge to loss on debt refinancing in the year ended December 31, 2006 of $5,626,000.

In July 2007, the Partnership used a portion of the proceeds from the equity offering to repay the $50,000,000 outstanding principal balance of term loan against the credit facility, together with accrued interest. Unamortized loan origination costs of $503,000 were written off and charged to loss on debt refinancing in the year ended December 31, 2007.

8. Other Assets

Intangible assets, net — Intangible assets, net consist of the following. The weighted average amortization period for permits and licenses is fifteen years and for customer contracts is twenty four years.

	Permits and Licenses	Customer Contracts	Total
		(in thousands)	
Balance at January 1, 2006	$ 11,040	$ 5,330	$ 16,370
Additions	-	63,202	63,202
Amortization	(793)	(1,856)	(2,649)
Balance at December 31, 2006	10,247	66,676	76,923
Additions	-	5,242	5,242
Disposals	(108)	-	(108)
Amortization	(771)	(3,482)	(4,253)
Balance at December 31, 2007	$ 9,368	$ 68,436	$ 77,804

The expected amortization of the intangible assets for each of the five succeeding years is as follows.

Year ending December 31,	Total (in thousands)
2008	$ 3,780
2009	3,780
2010	3,780
2011	3,643
2012	3,452

Goodwill — Goodwill consists of the following.

	Gathering and Processing	Transportation	Total
		(in thousands)	
Balance at January 1, 2006	$ 23,309	$ 34,243	$ 57,552
Additions	-	-	-
Balance at December 31, 2006	23,309	34,243	57,552
Additions	36,523	-	36,523
Balance at December 31, 2007	$ 59,832	$ 34,243	$ 94,075

9. Fair Value of Financial Instruments

The estimated fair value of financial instruments was determined using available market information and valuation methodologies. The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to their short-term maturities. Restricted cash and related escrow payable approximate fair value due to the relatively short-term settlement period of the escrow payable. Risk management assets and liabilities are carried at fair value. Long-term debt other than the senior notes was comprised of borrowings under which, at December 31, 2007 and 2006, accrued interest under a floating interest rate structure. Accordingly, the carrying value approximates fair value for the long term debt amounts outstanding. The estimated fair value of the senior notes based on third party market value quotations was $367,778,000 as of December 31, 2007.

Table of Contents

10. Leases

The Partnership leases office space and certain equipment for various periods and determined that these leases are operating leases. The Partnership also sold its 34 mile NGL pipeline located in east Texas for $3,000,000 on June 29, 2007 and simultaneously entered into transportation and operating agreements with the buyer. The Partnership accounted for this transaction as a sale-leaseback, which qualifies for capital lease treatment and the lease term is 20 years. Contingent rentals on this capital lease may be imposed if the Partnership increases the volume of NGLs shipped on the leased pipeline. The minimum lease payments escalate annually by an amount equal to the increase in a consumer price index beginning at mid-year 2010 and continue to escalate through the remainder of the term of the lease. The following table is a schedule of future minimum lease payments for operating leases that had initial or remaining noncancelable lease terms in excess of one year as of December 31, 2007.

For the year ended December 31,	Operating	Capital
	(in thousands)	
2008	$ 505	$ 402
2009	196	401
2010	194	409
2011	160	422
2012	27	436
Thereafter	-	8,010
Total minimum lease payments	$ 1,082	$ 10,080
Less: Amount representing estimated executory costs (such as maintenance and insurance), including profit thereon, included in minimum lease payments		2,054
Net minimum lease payments		8,026
Less: Amount representing interest		4,981
Present value of net minimum lease payments		$ 3,045

The following table sets forth the Partnership's assets and obligations under the capital lease which are included in other current and long-term liabilities on the balance sheet.

	December 31, 2007 (in thousands)
Gross amount included in gathering and transmission systems	$ 3,000
Less accumulated	(75)

amortization		
	$	2,925
Current obligation under capital lease	$	365
Noncurrent obligation under capital lease		2,680
	$	3,045

Total rent expense for operating leases, including those leases with terms of less than one year, was $1,597,000, $1,721,000, and $1,430,000 for the years ended December 31, 2007, 2006, and 2005, respectively. The Partnership subleases office space from an affiliate. The lease is classified as an operating lease and provides for minimum annual rentals of $148,000 through September 2010, plus contingent rentals based on a fixed allocation of operating expenses.

11. Commitments and Contingencies

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 the Partnership's business, financial condition, results of operations or cash flows.

Escrow Payable. At December 31, 2007, $6,029,000 remained in escrow pending the completion by El Paso Field Services, LP ("El Paso") of environmental remediation projects pursuant to the purchase and sale agreement ("El Paso PSA") related to the assets in north Louisiana and in the mid-continent area. In the El Paso PSA, El Paso indemnified the predecessor of our operating partnership RGS against losses arising from pre-closing and known environmental liabilities subject to a limit of $84,000,000 and subject to certain deductible limits. Upon completion of a Phase II environmental study, the Partnership notified El Paso of remediation obligations amounting to $1,800,000 with respect to known environmental matters and $3,600,000 with respect to pre-closing environmental liabilities.

Table of Contents

In January 2008, the Board of Directors of the General Partner and the Partnership has signed a settlement of the El Paso environmental remediation. Under the settlement, El Paso will clean up and obtain "no further action" letters from the relevant state agencies for three owned Partnership facilities. El Paso is not obligated to clean up properties leased by the Partnership, but it indemnified the Partnership for pre-closing environmental liabilities at that site. All sites for which the Partnership made environmental claims against El Paso are either addressed in the settlement or have already been resolved. The Partnership will release all but $1,500,000 from the escrow fund maintained to secure El Paso's obligations. This amount will be further reduced per a specified schedule as El Paso completes its cleanups and the remainder will be released upon completion.

Environmental. A Phase I environmental study was performed on the Waha assets in connection with the pre-acquisition due diligence process 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. The aggregate potential environmental remediation costs at specific locations were estimated to range from $1,900,000 to $3,100,000. No governmental agency has required the Partnership to undertake these remediation efforts. Management believes that the likelihood that it will be liable for any significant potential remediation liabilities identified in the study is remote. Separately, the Partnership acquired an environmental pollution liability insurance policy in connection with the acquisition to cover any undetected or unknown pollution discovered in the future. 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. No claims have been made.

TCEQ Notice of Enforcement. On February 15, 2008, the Texas Commission on Environmental Quality, or TCEQ, sent us a notice of enforcement, or NOE, relating to the air emissions at our Tilden processing plant. The NOE relates to 15 alleged violations occurring during the period from March 2006 through July 2007 of the emissions event reporting and recordkeeping requirements of the TCEQs rules. Specifically, it is alleged that one of our subsidiaries failed to report, using the TCEQ's electronic data base for emissions events, 15 emissions events within 24 hours of the incident, as required. These events occurred during times of failure of the Tilden plant sulphur recovery unit or ancillary equipment and resulted in the flaring of acid gas. Of these events, one relates to an alleged release of nearly 6 million pounds of sulphur dioxide and 64,000 pounds of hydrogen sulphide, 11 related to less than 2,500 pounds of sulphur dioxide and three related to more than 2,500 and less than 40,000 pounds of sulphur dioxide (including two releases of 126 and 393 pounds of hydrogen sulphide). In 2007, the subsidiary completed construction of an acid gas reinjection unit at the Tilden plant and permanently shut down the Sulphur Recovery Unit

All these emission incidents were reported by means of fax or telephone to the TCEQ pursuant to an informal procedure established with the TCEQ by the prior owner of the Tilden plant and, indeed, the subsidiary paid the emission fines in connection with all the incidents. Using that procedure, all except one were timely. The TCEQ has, prior to our subsidiary acquiring the Tilden facility, established its electronic data base for emissions events, but the subsidiary did not report using that electronic facility. It is the failure to report each incident timely using the electronic reporting procedure that is the subject of the NOE. Representatives of the Partnership are scheduled to meet with the staff of the TCEQ in the near future regarding the NOE. Management of the General Partner does not expect the NOE to have a material adverse effect on its results of operations or financial condition.

12. Related Party Transactions

The Partnership paid management and financial advisory fees in the amount of $1,073,000 were paid to an affiliate of HM Capital Partners in the year ended December 31, 2005. Concurrent with the closing of the Partnership's IPO, the Partnership paid $9,000,000 to an affiliate of HM Capital Partners to terminate a management services contract with a remaining tenor of nine years. TexStar paid $361,000 and $13,000 to HM Capital Partners for the years ended December 31, 2006 and 2005 in relation to a management services contract. In connection with the TexStar Acquisition, the Partnership paid $3,542,000 to terminate TexStar's management services contract.

Under an omnibus agreement, Regency Acquisition LP, the entity that formerly owned the General Partner, agreed to indemnify the Partnership in an aggregate 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 the Partnership and occurring or existing before that date. To date, no claims have been made against the omnibus agreement.

BlackBrush Oil & Gas, LP ("BBOG"), an affiliate of HM Capital Partners, is a natural gas producer on the Partnership's gas gathering and processing system. At the time of the TexStar Acquisition, BBOG entered into an agreement providing for the long term dedication of the production from its leases to the Partnership. In July 2007, BBOG sold its interest in the largest of these leases to an unrelated third party. BlackBrush Energy, Inc., a wholly owned subsidiary of HM Capital Partners, is the lessee of office space in the south Texas region. The Partnership subleased space from BlackBrush Energy, Inc., for which it paid $151,000, $70,000, and $13,000 in 2007, 2006, and 2005, respectively. The Partnership acquired compressors from BBOG for $1,800,000 on January 31, 2005. The purchase price exceeded the book value by $1,152,000. Since BBOG and the Partnership were commonly controlled entities, the net book value was recorded as the acquisition price. All of the Partnership's related party receivables, payables, revenues and expenses as disclosed in the consolidated financial statements relate to BBOG.

In July 2005, in connection with the amendment and restatement of the credit agreement, Regency Acquisition LP contributed an additional $15,000,000 of equity. In February 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 TexStar Acquisition, the promissory note was repaid in full. TexStar paid a transaction fee in the amount of $1,200,000 to an affiliate of HM Capital Partners upon completing its acquisition of the Como Assets. This amount was capitalized as a part of the purchase price.

The employees operating the assets of the Partnership and its subsidiaries and all those providing staff or support services are employees of the General Partner. Pursuant to the Partnership Agreement, our General Partner receives a monthly reimbursement for all direct and indirect expenses incurred on behalf of the Partnership. Reimbursements of $27,628,000 and $16,789,000 were recorded in the Partnership's financial statements during the years ended December 31, 2007 and 2006 as operating expenses or general and administrative expenses, as appropriate.

In conjunction with distributions by the Partnership on common and subordinated units, together with the general partner interest, HM Capital Partners and affiliates received cash distributions of $24,392,000 and $20,139,000 during the years ended December 31, 2007 and 2006 as a result of their ownership in the Partnership. In conjunction with distributions by the Partnership on common and subordinated units, together with the general partner interest, GE EFS and affiliates received cash distributions of $14,592,000 during the year ended December 31, 2007, as a result of their ownership in the Partnership.

GE EFS and certain members of the Partnership's management made a capital contribution aggregating to $7,735,000 to maintain the General Partner's two percent interest in the Partnership.

As a part of the GE EFS Acquisition, affiliates of HM Capital Partners entered into an agreement to hold 4,692,417 of the Partnership's common units for a period of 180 days. In addition, a separate affiliate of HM Capital Partners entered into an agreement to hold 3,406,099 of the Partnership's common units for a period of one year.

Table of Contents

Concurrent with the GE EFS acquisition, eight members of the Partnership's senior management, together with two independent directors, entered into an agreement to sell an aggregate of 1,344,551 subordinated units for a total consideration of $24.00 per unit. Additionally, GE EFS entered into a subscription agreement with four officers and certain other management of the Partnership whereby these individuals acquired an 8.2 percent indirect economic interest in the General Partner.

13. Concentration Risk
The following table provides information about the extent of reliance on major customers and gas suppliers. Total revenues and cost of gas and liquids from transactions with single external customer or supplier amounting to 10 percent or more of revenues or cost of gas and liquids are disclosed below, together with the identity of the reporting segment.

			Year Ended	
	Reporting Segment	December 31, 2007	December 31, 2006	December 31, 2005
Customer			(in thousands)	
Customer A	Transportation	*	$ 89,736	$ 132,539
Customer B	Gathering and Processing	*	*	76,115
Supplier				
Supplier A	Transportation	*	*	$ 93,188
Supplier B	Transportation	$ 157,046	*	63,398
Supplier C	Transportation	*	*	75,414
Supplier D	Gathering and Processing	*	$ 67,751	*

* Amounts are less than 10 percent of the total revenues or cost of gas and liquids.

The Partnership is a party to various commercial netting agreements that allow it and contractual counterparties to net receivable and payable obligations. These agreements are customary and the terms follow standard industry practice. In the opinion of management, these agreements reduce the overall counterparty risk exposure.

14. Segment Information
As of December 31, 2007, the Partnership has two reportable segments: i) gathering and processing and ii) transportation. Gathering and processing involves the collection of hydrocarbons from producer wells across the five operating regions and transportation of them to a plant where water and other impurities such as hydrogen sulfide and carbon dioxide are removed. Treated gas is then processed to remove the natural gas liquids. The treated and processed natural gas is then transported to market separately from the natural gas liquids. The Partnership aggregates the results of its gathering and processing activities across five geographic regions into a single reporting segment.

The transportation segment uses pipelines to transport natural gas from receipt points on its system to interconnections with larger pipelines or trading hubs and other markets. The Partnership performs transportation services for shipping customers under firm or interruptible arrangements. In either case, revenues are primarily fee based and involve minimal direct exposure to commodity price fluctuations. The Partnership also purchases natural gas at the inlets to the pipeline and sells this gas at its outlets. The north Louisiana intrastate pipeline operated by this segment serves the Partnership's gathering and processing facilities in the same area and those transactions create the intersegment revenues shown in the table below.

Management evaluates the performance of each segment and makes capital allocation decisions through the separate consideration of segment margin and operation and maintenance expenses. Segment margin is defined as total revenues, including service fees, less cost of gas and liquids. Management believes segment margin is an important measure because it is directly related to volumes and commodity price changes. Operation and maintenance expenses are 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 operation and maintenance expenses. These expenses are largely independent of the volume throughput but fluctuate depending on the activities performed during a specific period. The Partnership does not deduct operation and maintenance expenses from total revenues in calculating segment margin because management separately evaluates commodity volume and price changes in segment margin.

Results for each statement of operations period, together with amounts related to balance sheets for each segment, are shown below.

Table of Contents

	Gathering and Processing	Transportation	Corporate (in thousands)	Eliminations	Total
External Revenue					
Year ending December 31, 2007	$ 790,677	$ 377,377	$ -	$ -	$ 1,168,054
Year ending December 31, 2006	645,770	251,095	-	-	896,865
Year ending December 31, 2005	505,721	203,680	-	-	709,401
Intersegment Revenue					
Year ending December 31, 2007	-	101,734	-	(101,734)	-
Year ending December 31, 2006	-	39,504	-	(39,504)	-
Year ending December 31, 2005	-	57,066	-	(57,066)	-
Cost of Gas and Liquids					
Year ending December 31, 2007	658,100	318,045	-	-	976,145
Year ending December 31, 2006	534,398	206,048	-	-	740,446
Year ending December 31, 2005	444,857	188,008	-	-	632,865
Segment Margin					
Year ending December 31, 2007	132,577	59,332	-	-	191,909
Year ending December 31, 2006	111,372	45,047	-	-	156,419
Year ending December 31, 2005	60,864	15,672	-	-	76,536

Operation and Maintenance					
Year ending December 31, 2007	40,970	4,504	-	-	45,474
Year ending December 31, 2006	35,008	4,488	-	-	39,496
Year ending December 31, 2005	22,362	1,929	-	-	24,291
Depreciation and Amortization					
Year ending December 31, 2007	36,974	13,545	1,220	-	51,739
Year ending December 31, 2006	26,831	11,927	896	-	39,654
Year ending December 31, 2005	17,955	4,666	550	-	23,171
Assets					
December 31, 2007	781,944	329,862	62,071	-	1,173,877
December 31, 2006	648,116	316,038	48,931	-	1,013,085
Investments in Unconsolidated Subsidiaries					
December 31, 2007	-	-	-	-	-
December 31, 2006	5,616	-	-	-	5,616
Goodwill					
December 31, 2007	59,832	34,243	-	-	94,075
December 31, 2006	23,309	34,243	-	-	57,552
Expenditures for Long-Lived Assets					
Year ending December 31, 2007	106,331	16,555	416	-	123,302
Year ending December 31, 2006	192,115	29,810	1,725	-	223,650
Year ending December 31, 2005	140,463	158,079	923	-	299,465

The table below provides a reconciliation of total segment margin to net loss from continuing operations.

	Year Ended December 31, 2007	December 31, 2006	December 31, 2005
	(in thousands)		
Net loss from continuing operations	$ (18,697)	$ (7,244)	$ (11,592)
Add (deduct):			
Operation and maintenance	45,474	39,496	24,291
General and administrative	39,543	22,826	15,039
Loss on assets sales	1,522	-	-
Management services termination fee	-	12,542	-
Transaction expenses	420	2,041	-
Depreciation and amortization	51,739	39,654	23,171
Interest expense, net	52,016	37,182	17,880
Loss on debt refinancing	21,200	10,761	8,480
Other income and deductions, net	(1,308)	(839)	(733)
Total segment margin	$ 191,909	$ 156,419	$ 76,536

15. Equity-Based Compensation

The Partnership's long-term incentive plan ("LTIP") for the Partnership's employees, directors and consultants covering an aggregate of 2,865,584 common units. Awards under the LTIP have been made since completion of the Partnership's IPO. All outstanding,

Table of Contents

unvested LTIP awards at the time of the GE EFS Acquisition vested upon the change of control. As a result, the Partnership recorded a one-time charge of $11,928,000 during the year ended December 31, 2007 in general and administrative expenses. LTIP awards made subsequent to the GE EFS Acquisition vest on the basis of one-fourth of the award each year. Options expire ten years after the grant date. LTIP compensation expense of $15,534,000 and $2,906,000 is recorded in general and administrative in the statement of operations for the years ended December 31, 2007 and 2006, respectively.

The fair value of each option award is estimated on the date of grant using the Black-Scholes Option Pricing Model. The Partnership used the simplified method outlined in Staff Accounting Bulletin No. 107 for estimating the exercise behavior of option grantees, given the absence of historical exercise data to provide a reasonable basis upon which to estimate expected term due to the limited period of time its units have been publicly traded. Upon the exercise of the common unit options, the Partnership intends to settle these obligations with common units on a net basis. The following assumptions apply to the options granted during the periods presented.

	Year Ended December 31, 2007	Year Ended December 31, 2006
Weighted average expected life (years)	4	4
Weighted average expected dividend per unit	$ 1.51	$ 1.40
Weighted average grant date fair value of options	$ 2.31	$ 1.32
Weighted average risk free rate	4.6%	4.25%
Weighted average expected volatility	16.0%	15.0%
Weighted average expected forfeiture rate	11.0%	5.0%

The common unit options activity for the years ending December 31, 2007 and 2006 is as follows.

2007 Common Unit Options	Units	Weighted Average Exercise Price	Weighted Average Contractual Term (Years)	Aggregate Intrinsic Value * (in thousands)
Outstanding at beginning of period	909,600	$ 21.06		
Granted	21,500	27.18		
Exercised	(149,934)	21.78		$ 1,738
Forfeited or expired	(42,498)	21.85		
Outstanding at end of period	738,668	21.05	8.2	9,104

Exercisable at end of period	738,668	21.05		9,104

2006 Common Unit Options	Units	Weighted Average Exercise Price	Weighted Average Contractual Term (Years)	Aggregate Intrinsic Value * (in thousands)
Outstanding at beginning of period	-	$ -		
Granted	943,900	21.05		
Exercised	-	-		
Forfeited or expired	(34,300)	20.75		
Outstanding at end of period	909,600	21.06	9.3	$ 5,522
Exercisable at end of period	-	-	-	-

* Intrinsic value equals the closing market price of a unit less the option strike price, multiplied by the number of unit options outstanding.

The Partnership will make distributions to non-vested restricted common units at the same rate as the common units. Restricted common units are subject to contractual restrictions against transfer which lapse over time; non-vested restricted units are subject to forfeitures on termination of employment. The Partnership expects to recognize $11,793,000 of compensation expense related to the grants under LTIP ratably over the future vesting period.

The restricted (non-vested) common unit activity for the years ending December 31, 2007 and 2006 is as follows.

Table of Contents

2007 Restricted (Non-Vested) Common Units	Units		Weighted Average Grant Date Fair Value
Outstanding at beginning of period	516,500	$	21.06
Granted	615,500		30.44
Vested	(684,167)		22.91
Forfeited or expired	(50,333)		27.20
Outstanding at end of period	397,500	$	31.62

2006 Restricted (Non-Vested) Common Units	Units		Weighted Average Grant Date Fair Value
Outstanding at beginning of period	-		-
Granted	516,500	$	21.06
Forfeited or expired	-		-
Outstanding at end of period	516,500	$	21.06

16. Subsequent Events

Acquisition of FrontStreet Hugoton, LLC. On January 7, 2008, the Partnership, through RGS, acquired all the outstanding equity (the "FrontStreet Acquisition") of FrontStreet Hugoton, LLC from ASC Hugoton LLC, ("ASC"), and FrontStreet EnergyOne LLC, ("EnergyOne" and, together with ASC, the "Sellers"). The FrontStreet Acquisition was completed in accordance with the Contribution Agreement, dated December 10, 2007 (the "Contribution Agreement"), between the Partnership, RGS, and the Sellers, solely for purposes of assuring to the Partnership and RGS the performance by ASC of certain of its obligations under the Contribution Agreement, as amended. FrontStreet owns a gas gathering system located in Kansas and Oklahoma, which gas gathering system is operated by BP America Production Co., a wholly-owned subsidiary of BP plc.

The total purchase price, subject to customary post-closing adjustments, paid by the Partnership for FrontStreet consisted of (1) the issuance of 4,701,034 Class E common units of the Partnership to ASC, which were valued at $135,014,000 and (2) the payment of $11,752,000 in cash to EnergyOne. RGS financed the cash portion of the purchase price out of its $500,000,000 revolving credit facility. In connection with the FrontStreet Acquisition, the General Partner entered into Amendment No. 3 to the Amended and Restated Agreement of Limited Partnership of the Partnership, which created the Partnership's Class E common units. The Class E common units have the same terms and conditions as the Partnership's common units, except that the Class E common units were not entitled to participate in earnings or distributions of operating surplus by the Partnership. The Class E common units were issued in a private offering conducted in accordance with the exemption from the registration requirements of the Securities Act of 1933, as amended, as afforded by Section 4(2) thereof. The Class E common units may be converted into common units on a one-for-one basis anytime from and after February 15, 2008.

Because the FrontStreet Acquisition is a transaction between commonly controlled entities (i.e., the buyer and the sellers were each affiliates of GECC), the Partnership will be required to account for the acquisition in a manner similar to the pooling of interest method of accounting. Under this method of accounting, the FrontStreet Acquisition will reflect historical balance sheet data for both the Partnership and FrontStreet instead of reflecting the fair market value of FrontStreet's assets and liabilities. Further, as a result of this method of accounting, certain transaction costs that would normally be capitalized will be expensed. The Partnership will recast its financial statements to include the operations of FrontStreet from June 18, 2007 (the date upon which common control began) forward in 2008.

Acquisition of CDM Resource Management, Ltd. On January 15, 2008, the Partnership and ADJHR, LLC, an indirect wholly owned subsidiary of the Partnership ("Merger Sub"), consummated an agreement and plan of merger (the "Merger Agreement") with CDM Resource Management, Ltd. ("CDM"), CDM OLP GP, LLC, the sole general partner of CDM, and CDMR Holdings, LLC the sole limited partner of CDM (each a "CDM Partner" and together the "CDM Partners"). Upon closing CDM merged with and into Merger Sub, with Merger Sub continuing as the surviving entity after the merger (the "CDM Merger"). Following the merger, Merger Sub changed its name to CDM Resource Management LLC. CDM provides its customers with turn-key natural gas contract compression services to maximize their natural gas and crude oil production, throughput, and cash flow in Texas, Louisiana, and Arkansas. The Partnership will operate and manage CDM as a separate reportable segment.

The total purchase price, subject to customary post-closing adjustments, paid by the Partnership for the partnership interests of CDM consisted of (1) the issuance of an aggregate of 7,276,506 Class D common units of the Partnership, which were valued at $216,869,000, (2) the payment of an aggregate of $161,945,000 in cash to the CDM Partners, and (3) the assumption of $316,500,000 in CDM's debt obligations. Of those Class D common units issued, 4,197,303 Class D common units were deposited with an escrow agent pursuant to an escrow agreement. Such common units constitute security to the Partnership for a period of one year after the closing of the CDM Merger, with respect to any obligations of the CDM Partners under the Merger Agreement, including obligations for breaches of representation, warranties and covenants. In connection with the CDM Merger, the General Partner entered into Amendment No. 4 to the Amended and Restated Agreement of Limited Partnership of the Partnership, which created the Partnership's Class D common units. The Class D common units, which were issued at a 7.5 percent discount, have the same terms and conditions as the Partnership's common units, except that the Class D common units are not entitled to participate in distributions of operating surplus by the Partnership. The Class D common units automatically convert into common units on a one-for-one basis on the close of business on the first business day after the record date for the quarterly distribution on the common units for the quarter ending December 31, 2008. The Class D common units were issued in a private offering conducted in accordance with the exemption from the registration requirements of the Securities Act of 1933, as amended, as afforded by Section 4(2) thereof.

General Partner Capital Contribution. In January 2008, the General Partner made a capital contribution of $7,663,000 to maintain its two percent interest in the Partnership in respect of the FrontStreet Acquisition and the CDM acquisition.

Amendments of the Fourth Amended and Restated Credit Agreement. RGS entered into Amendment No. 4 to its Fourth Amended and Restated Credit Facility (the "4th Amendment") on January 15, 2008, thereby expanding its revolving credit facility thereunder to $750,000,000, and borrowed $476,000,000 in revolving loans thereunder. Such borrowings, together with cash on hand, were used for the following purposes: (i) $291,000,000 to repay the balance outstanding under CDM's bank credit facility, (ii) $25,500,000 to fund the purchase of compressors and other equipment held by CDM under capital leases, and (iii) $161,945,000 to fund the cash portion of the consideration issued to the CDM Partners in the CDM Merger. The 4th Amendment did not materially change the terms of the RGS revolving credit facility.

RGS entered into Amendment No. 5 to its Fourth Amended and Restated Credit Facility (the "5th Amendment") on February 13, 2008, thereby expanding its revolving credit facility thereunder to $900,000,000. The availability for letters of credit is $100,000,000. The Partnership has the option to request an additional $250,000,000 in revolving commitments with 10 business days written notice 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. The 5th Amendment did not materially change the terms of the RGS revolving credit facility.

Cash Distributions. On February 14, 2008, the Partnership paid a distribution of $0.40 per common and subordinated unit.

Acquisition of Nexus. On February 22, 2008, the Partnership entered into an Agreement and Plan of Merger (the "Nexus Merger Agreement") with Nexus Gas Partners, LLC, a Delaware limited liability company ("Nexus Member"), and Nexus Gas Holdings, LLC, a Delaware limited liability company ("Nexus") ("Nexus Acquisition"). The aggregate consideration to be paid is $85,000,000 in cash, subject to adjustment pursuant to customary closing adjustments. Upon consummation of the Nexus Acquisition, the Partnership will acquire Nexus' rights under a Purchase and Sale Agreement (the "Sonat Agreement") between Nexus and Southern Natural Gas Company ("Sonat"). Pursuant to the Sonat Agreement Nexus will purchase 136 miles of pipeline from Sonat that would enable the Nexus gathering system to be integrated into the Partnership's north Louisiana asset base (the "Sonat

Acquisition"). The Sonat Acquisition is subject to abandonment approval by the FERC and other customary closing conditions. Upon the closing of the Sonat Acquisition, the Partnership will pay Sonat $28,000,000, and, if the closing occurs on or prior to March 1, 2010, on certain terms and conditions as provided in the Merger Agreement, the Partnership will make an additional payment of $25,000,000 to the Nexus Member.

In connection with the closing of the Merger, $8,500,000 will be deposited with an escrow agent to secure certain indemnification obligations of Member under the Merger Agreement. The escrow will remain in place for one year after the closing of the Merger, and the balance of the escrow upon termination of the escrow (net of any pending claims) will be released to Member.

The Nexus Acquisition is subject to approval under the Hart-Scott-Rodino Antitrust Improvements Act and other customary closing conditions. The closing is expected to occur in late first quarter or early second quarter 2008. We anticipate funding the Merger consideration through borrowings under the existing revolving credit facility.

Table of Contents

17. Quarterly Financial Data (Unaudited)

Quarter Ended	Operating Revenues	Operating Income (Loss)	Net Income (Loss)	Basic and Diluted Earnings per Common and Subordinated Unit (1)	Basic and Diluted Earnings per Class B Common Unit (1)	Basic and Diluted Earnings per Class C Common Unit (1)
	(in thousands except earnings per unit)					
2007						
March 31	$ 256,428	$ 13,480	$ (1,295)	$ (0.06)	$ -	$ 0.48
June 30	301,536	8,436	(7,577)	(0.16)	-	-
September 30	285,441	18,435	(12,796)	(0.23)	-	-
December 31	324,649	12,860	2,040	0.03	-	-
2006						
March 31	231,266	1,500	(6,319)	(0.18)	(0.18)	-
June 30	214,658	11,948	3,760	0.08	0.08	-
September 30	229,132	11,987	(11,272)	(0.28)	(0.14)	0.11
December 31	221,809	14,425	6,587	0.08	-	1.15

(1) The following table depicts the change to the quarterly earnings (loss) per unit data for each class of common units as compared to previously disclosed amounts in the respective quarterly filings. The quarterly amounts have been corrected for an error made in the calculation of loss per unit resulting from the issuance of Class C common units at a discount as further discussed in the loss per unit note.

	Three Months Ended		
	September 30, 2006	December 31, 2006	March 31, 2007
Common and subordinated unit	$ (0.01)	$ (0.09)	$ (0.03)
Class B common unit	-	-	-
Class C common unit	0.11	1.15	0.48