Regency Energy Partners LP
Form 10-Q
May 15, 2007

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

(Mark One)

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 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: 0001-338613

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

DELAWARE	**16-1731691**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1700 PACIFIC AVENUE, SUITE 2900 DALLAS, TX	**75201**
(Address of principal executive offices)	(Zip Code)

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

NONE
(Former name, former address and former fiscal year, if changed since last report.)

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. þ Yes o No

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

Large accelerated filer o Accelerated filer o Non-accelerated filer þ

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

The issuer had 28,576,981 common units and 19,103,896 subordinated units outstanding as of May 8, 2007.

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 sim 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 and 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.

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.

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Part I Financial Information
Item 1. Financial Statements

Regency Energy Partners LP
Condensed Consolidated Balance Sheets
Unaudited
(In thousands except unit data)

	March 31, 2007	December 31, 2006
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 8,504	$ 9,139
Restricted cash	5,847	5,782
Accounts receivable, net of allowance of $94 in 2007 and $181 in 2006	99,310	96,993
Related party receivables	397	755
Assets from risk management activities	22	2,126
Other current assets	4,681	5,279
Total current assets	118,761	120,074
Property, plant and equipment		
Gas plants and buildings	103,685	103,490
Gathering and transmission systems	540,821	529,776
Other property, plant and equipment	76,106	73,861
Construction-in-progress	109,641	85,277
Total property, plant and equipment	830,253	792,404
Less accumulated depreciation	(68,133)	(58,370)
Property, plant and equipment, net	762,120	734,034
Other assets:		
Intangible assets, net of amortization of $5,669 in 2007 and $4,676 in 2006	75,930	76,923
Long-term assets from risk management activities	111	1,674
Other, net of amortization of debt issuance costs of $1,505 in 2007 and $946 in 2006	17,085	17,212
Investments in unconsolidated subsidiaries		5,616
Goodwill	57,552	57,552
Total other assets	150,678	158,977
TOTAL ASSETS	$ 1,031,559	$ 1,013,085
LIABILITIES & PARTNERS CAPITAL		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 109,053	$ 117,254

Related party payables	389	280
Escrow payable	5,848	5,783
Accrued taxes payable	2,961	2,758
Liabilities from risk management activities	9,511	3,647
Interest payable	14,916	2,998
Other current liabilities	1,090	2,594
Total current liabilities	143,768	135,314
Long-term liabilities from risk management activities	2,989	145
Other long-term liabilities	1,350	269
Long-term debt	698,100	664,700
Partners Capital:		
Common units (29,915,745 and 21,969,480 units authorized; 27,824,914 and 19,620,396 units issued and outstanding at March 31, 2007 and December 31, 2006)	155,613	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 March 31, 2007 and December 31, 2006)	35,988	43,240
General partner interest	5,231	5,543
Accumulated other comprehensive income (loss)	(11,480)	1,019
Total partners capital	185,352	212,657
TOTAL LIABILITIES AND PARTNERS CAPITAL	$ 1,031,559	$ 1,013,085

See accompanying notes to unaudited condensed consolidated financial statements

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

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
REVENUES		
Gas sales	$ 167,384	$ 158,472
NGL sales	63,541	56,136
Gathering, transportation and other fees, including related party amounts of $353 in 2007 and $519 in 2006	19,878	12,704
Net realized and unrealized loss from risk management activities	(85)	(1,657)
Other	5,710	5,611
Total revenues	256,428	231,266
OPERATING COSTS AND EXPENSES		
Cost of gas and liquids, including related party amounts of $5,418 in 2007 and $513 in 2006	211,937	196,736
Operation and maintenance	10,925	9,445
General and administrative	6,851	5,416
Loss on sale of assets	1,808	
Management services termination fee		9,000
Depreciation and amortization	11,427	9,169
Total operating costs and expenses	242,948	229,766
OPERATING INCOME	13,480	1,500
Interest expense, net	(14,885)	(8,001)
Other income and deductions, net	110	182
NET LOSS	$ (1,295)	$ (6,319)
Less: Net income from January 1-31, 2006		1,564
Net loss for partners	$ (1,295)	$ (7,883)
General partner s interest	(26)	(158)
Limited partners interest	$ (1,269)	$ (7,725)
Basic and diluted earnings per unit:		
Net loss allocated to common units	$ (635)	$ (3,402)

Weighted average number of common units outstanding		23,252,059		19,103,896
Loss per common unit	$	(0.03)	$	(0.18)
Distributions declared per unit	$	0.38	$	0.2217
Net loss allocated to subordinated units		(634)	$	(3,402)
Weighted average number of subordinated units outstanding		19,103,896		19,103,896
Loss per subordinated unit	$	(0.03)		(0.18)
Distributions declared per unit	$	0.38	$	0.2217
Net loss allocated to Class B common units	$		$	(921)
Weighted average number of Class B common units outstanding		2,644,074		5,173,189
Loss per Class B common unit	$		$	(0.18)
Distributions declared per unit	$		$	
Net loss allocated to Class C common units	$		$	
Weighted average number of Class C common units outstanding		1,238,095		
Loss per Class C common unit	$		$	
Distributions declared per unit	$		$	

See accompanying notes to unaudited condensed consolidated financial statements

Regency Energy Partners LP
Condensed Consolidated Statement of Partners Capital
Unaudited
(In thousands except unit data)

	Units									Accumulated Other	
	Common	Class B	Class C	Subordinated	Common Unitholders	Class B Unitholders	Class C Unitholders	Subordinated Unitholders	General Partner Interest	Comprehensive Income (Loss)	To
ce nber 31,	19,620,396	5,173,189	2,857,143	19,103,896	$ 42,192	$ 60,671	$ 59,992	$ 43,240	$ 5,543	$ 1,019	$ 21
rsion of B and C mmon	8,030,332	(5,173,189)	(2,857,143)		120,663	(60,671)	(59,992)				
ce of ted on units	191,000										
tures of ted on units	(20,000)										
se of on unit s	3,186										
ased nsation ses					653			450			
al r butions									6		
r utions					(7,260)			(7,068)	(292)		(1
ss					(635)			(634)	(26)		(
dging y ified to gs										(54)	
ange in lue of ow s										(12,445)	(1
ce h 31,	27,824,914			19,103,896	$ 155,613	$	$	$ 35,988	$ 5,231	$ (11,480)	$ 18

See accompanying notes to unaudited condensed consolidated financial statements

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Regency Energy Partners LP
Consdensed Consolidated Statements of Comprehensive Loss
Unaudited
(In thousands)

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
Net loss	$ (1,295)	$ (6,319)
Hedging losses reclassified to earnings	(54)	813
Net change in fair value of cash flow hedges	(12,445)	4,427
Comprehensive loss	$ (13,794)	$ (1,079)

See accompanying notes to unaudited condensed consolidated financial statements

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Regency Energy Partners LP
Condensed Consolidated Statement of Cash Flows
Unaudited
(In thousands)

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
OPERATING ACTIVITIES		
Net loss	$ (1,295)	$ (6,319)
Adjustments to reconcile net loss to net cash flows provided by (used in) operating activities:		
Depreciation and amortization	11,986	9,318
Equity income	(43)	(91)
Risk management portfolio valuation changes	(124)	(191)
Loss on sale of assets	1,808	
Unit based compensation expenses	1,103	314
Cash flow changes in current assets and liabilities:		
Accounts receivable	(1,959)	16,938
Other current assets	598	921
Accounts payable and accrued liabilities	5,220	(23,535)
Accrued taxes payable	203	273
Interest payable	11,918	
Other current liabilities	(1,504)	12
Other assets	(441)	2,515
Other liabilities		(626)
Net cash flows provided by (used in) operating activities	27,470	(471)
INVESTING ACTIVITIES		
Capital expenditures	(47,501)	(30,454)
Investments in unconsolidated subsidiaries		(57)
Acquisition of investment in unconsolidated subsidiary	(5,000)	133
Proceeds from sale of assets	5,610	
Net cash flows used in investing activities	(46,891)	(30,378)
FINANCING ACTIVITIES		
Net borrowings under revolving credit facilities	33,400	22,125
Debt issuance costs		(151)
Proceeds from IPO, net of issuance costs		252,734
Capital reimbursement to HM Capital Partners		(243,757)
Proceeds from exercise of over allotment option		26,163
Over allotment option proceeds to HM Capital Partners		(26,163)
Partner contributions	6	
Partner distributions	(14,620)	

Net cash flows provided by financing activities	18,786	30,951
Net increase (decrease) in cash and cash equivalents	(635)	102
Cash and cash equivalents at beginning of period	9,139	3,686
Cash and cash equivalents at end of period	$ 8,504	$ 3,788
Supplemental cash flow information		
Interest paid, net of amounts capitalized	$ 2,540	$ 6,251
Non-cash capital expenditures in accounts payable	10,509	15,069
Non-cash capital expenditures for consolidation of investment in previously unconsolidated subsidiary	5,650	

See accompanying notes to unaudited condensed consolidated financial statements

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Regency Energy Partners LP
Notes to Unaudited Condensed Consolidated Financial Statements

1. Organization and Summary of Significant Accounting Policies

Organization and Basis of Presentation. The unaudited condensed consolidated financial statements presented herein contain the results of Regency Energy Partners LP, a Delaware limited partnership (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). On August 15, 2006, the Partnership, through RGS, acquired all the outstanding equity of TexStar Field Services, L.P. and its general partner, TexStar GP, LLC (the TexStar Acquisition), from HMTF Gas Partners II, L.P. (HMTF Gas Partners), an affiliate of HM Capital Partners LLC (HM Capital Partners). Hicks Muse Equity Fund V, L.P. (Fund V) and its affiliates, through HM Capital Partners, control Regency GP LP, the general partner of the Partnership (the General Partner). Fund V also controls HMTF Gas Partners through HM Capital Partners. Because the TexStar Acquisition was a transaction between commonly controlled entities, the Partnership is required to account for the TexStar Acquisition in a manner similar to a pooling of interests. Information included in these financial statements for periods presented prior the consummation of the TexStar Acquisition has been adjusted to reflect the TexStar acquisition.

The accompanying unaudited condensed 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.

The unaudited financial information as of, and for the three months ended, March 31, 2007 has been prepared on the same basis as the audited consolidated financial statements included in the Partnership s Annual Report on Form 10-K for the year ended December 31, 2006. In the opinion of the Partnership s management, such financial information reflects all adjustments necessary for a fair presentation of the financial position and the results of operations for such interim periods in accordance with accounting principles generally accepted in the United States of America (GAAP). All intercompany items and transactions have been eliminated in consolidation. Certain information and footnote disclosures normally included in annual consolidated financial statements prepared in accordance with GAAP have been omitted pursuant to the rules and regulations of the Securities and Exchange Commission. The Partnership reclassified interest payable at December 31, 2006 to conform to the current year presentation.

Use of Estimates. The unaudited condensed consolidated financial statements have been prepared in conformity with GAAP and, of necessity, include the use of estimates and assumptions by management. Actual results could differ from these estimates.

Intangible Assets. The total gross carrying amount of intangible assets that were subject to amortization was $81,599,000 at March 31, 2007 and December 31, 2006. Aggregate amortization expense for the three months ended March 31, 2007 and 2006 was $993,000 and $468,000, respectively.

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

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In September 2006, the FASB issued Statement of Financial Accounting Standard (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. The Partnership is currently evaluating the potential effects 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 effects on its financial position, results of operations or cash flows of the adoption of this standard.

2. Loss per Limited Partner Unit

The following data show the amounts used in computing limited partner loss per unit.

	Three Months Ended			
	March 31, 2007		March 31, 2006	
	(in thousands except unit data and per unit data)			
Net loss for partners	$	(1,295)	$	(7,883)
Adjustments:				
General partner s allocation of prior year losses				
General partner s interest		(26)		(158)
Limited partners interest in net loss	$	(1,269)	$	(7,725)
Net loss allocated to common unitholders	$	(635)	$	(3,402)
Weighted average common limited partner units basic and diluted		23,252,059		19,103,896
Common limited partners basic and diluted loss per unit	$	(0.03)	$	(0.18)
Net loss allocated to subordinated unitholders	$	(634)	$	(3,402)
Weighted average subordinated limited partner units basic and diluted		19,103,896		19,103,896
Subordinated limited partners basic and diluted loss per unit	$	(0.03)	$	(0.18)
Net loss allocated to Class B unitholders	$		$	(921)
Weighted average Class B common units outstanding *		2,644,074		5,173,189
Class B common limited partners basic and diluted loss per unit	$		$	(0.18)
Net loss allocated to Class C unitholders	$		$	
Weighted average Class C common units outstanding *		1,238,095		
Class C common limited partners basic and diluted loss per unit	$		$	

* Converted into common units prior to the end of March 31, 2007.

Loss per unit for the three months ended March 31, 2006 reflects only the two 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. Potentially dilutive units related to the Partnership s long-term incentive plan of 884,866 and 654,000 common unit options and 687,500 and 362,500 restricted common units have been excluded from diluted loss per unit as the effect is antidilutive for the three months ended March 31, 2007 and 2006 as the Partnership reported a net loss. Furthermore, 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.

In accordance with SFAS No. 128, the Partnership allocates net income or loss to each class of equity security in

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proportion to the amount of distributions earned during that period. Since the Class B common units were deemed to be outstanding for the three months ended March 31, 2006, a portion of net loss was allocated to this class of equity because they were not expressly prohibited from receiving distributions. 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 tax years.

3. Acquisitions and Dispositions

Palafox Joint Venture. The Partnership acquired the outstanding interest in the Palafox Joint Venture not owned by it (50 percent) for $5,000,000 effective February 1, 2007. Including the net book value of $5,057,000 immediately prior to its acquisition, the Partnership allocated $10,057,000 to gathering and transmission systems ($9,464,000) and to working capital accounts ($593,000) in the three months ended March 31, 2007.

South Texas Assets. 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 one-time charge of $1,808,000.

TexStar Acquisition. Since the Partnership s acquisition of TexStar 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 loss for the previously separate entities and the combined amounts for the three months ended March 31, 2006 presented in these unaudited condensed consolidated financial statements.

		Three Months Ended March 31, 2006 (in thousands)
Revenues		
Regency Energy Partners	$	201,475
TexStar Field Services		29,791
Combined		231,266
Net loss		
Regency Energy Partners		(6,270)
TexStar Field Services		(49)
Combined	$	(6,319)

4. Risk Management Activities

As of March 31, 2007, the Partnership s hedging positions accounted for as cash flow hedges reduce exposure to variability of future commodity prices through 2009. The net fair value of the Partnership s risk management activities constituted a liability of $12,367,000 as of March 31, 2007. The Partnership expects to reclassify $9,046,000 of hedging losses into earnings from other comprehensive income (loss) in the next twelve months. The Partnership calculated an immaterial amount of ineffectiveness for certain hedges and therefore recorded no amounts to the statement of operations for hedge ineffectiveness for any period presented.

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5. Long-Term Debt

Long-term debt obligations of the Partnership are as follows:

	March 31, 2007	December 31, 2006
	(in thousands)	
Senior notes	$ 550,000	$ 550,000
Term loans	50,000	50,000
Revolving loans	98,100	64,700
Total	698,100	664,700
Less: current portion		
Long-term debt	$ 698,100	$ 664,700
Availability		
Total credit facility limit	$ 300,000	$ 300,000
Term loans	(50,000)	(50,000)
Revolver loans	(98,100)	(64,700)
Letters of credit	(12,003)	(5,183)
Total	$ 139,897	$ 180,117

The outstanding balances of term debt and revolver debt under the credit facility bear interest at LIBOR plus a margin or Alternative Base Rate (equivalent to the US prime lending rate) plus a margin, or a combination of both. The weighted average interest rates for the revolving and term loan facilities, including interest rate swap settlements, commitment fees, and amortization of debt issuance costs were 8.78 percent and 7.17 percent for the three months ended March 31, 2007 and 2006, respectively. The outstanding balances of the senior notes bear interest at a fixed rate of 8.375 percent. At March 31, 2007, the Partnership was in compliance with the covenants of the credit facility and senior notes.

The Partnership and Regency Energy Finance Corp. (Finance Corp), a wholly-owned subsidiary of RGS, are co-issuers of the senior notes. Finance Corp. does not have any operations of any kind and will not have any 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.

6. Commitments and Contingencies

Legal. Blackbrush Oil & Gas LLC, owned by an affiliate of HM Capital that was the seller in our acquisition of TexStar Field Services, L.P., and certain of its subsidiaries are defendants in a wrongful death action styled *Takas v. Strait Energy Services LLC et al.* brought in state district court in Jim Wells County, Texas. The claim for both actual and punitive damages is made on behalf of the wife of the driver of a tractor trailer truck who was killed when the truck was struck by a train at a railway crossing. The truck was owned by a subcontractor working on, and was enroute to, a construction site relating to a pipeline owned by an entity that was then a subsidiary of TexStar. This accident occurred on July 15, 2005, prior to our acquisition of TexStar on August 15, 2006. We have been advised by representatives of Blackbrush that the entity that owned the pipeline, which is now our subsidiary (Regency Frio NewLine LP), is likely to be named as a defendant in the litigation as a result of Blackbrush s reply to the complaint. We have notified our insurance carrier regarding this matter, and we do not expect it to have a material adverse effect on our financial condition or our results of operations.

The Partnership is involved in various other 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 March 31, 2007, $5,848,000 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 s predecessor, (Regency LLC Predecessor), 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, Regency LLC Predecessor 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. Upon satisfactory completion of the remediation by El Paso, the amount held in escrow will be released. These contractual rights of Regency LLC Predecessor were continued by the Partnership.

Environmental. Waha Phase I. 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 estimated potential environmental remediation costs at specific locations were $1,900,000 to $3,100,000. No governmental agency has required that the Partnership undertakes 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.

Regulatory Environment. In August 2005, Congress enacted and the President signed the Energy Policy Act of 2005. With respect to the oil and gas industry, the new legislation focuses on the exploration and production sector, interstate pipelines, and refinery facilities. In many cases, the Act requires action by various government agencies over the near to mid-term. Management is unable to determine what impact, if any, the Act will have on its operations and cash flows.

7. Related Party Transactions

BlackBrush Oil & Gas, LP (BBOG), an affiliate of the Partnership, is a natural gas producer on the Partnership s gas gathering and processing system. At the time of the Partnership s acquisition of TexStar, BBOG entered into an agreement providing for the long term dedication of the production from its leases. BlackBrush Energy, Inc., a wholly owned subsidiary of HM Capital, subleases office space to the Partnership for which it paid $37,000 in the three months ended March 31, 2007.

During the three months ended March 31, 2007 and 2006, the Partnership generated related party revenues of $353,000 and $519,000 on transportation and compression of natural gas for BBOG. The Partnership incurred related party expenses of $5,418,000 and $513,000 for the three months ended March 31, 2007 and 2006. As of March 31, 2007 and December 31, 2006, the Partnership s related party accounts receivable balances from BBOG were $397,000 and $755,000, respectively. Related party payables to BBOG were $389,000 and $280,000 as of March 31, 2007 and December 31, 2006, respectively.

The employees operating the assets of the Partnership and its subsidiaries and all those providing staff or support services are employees of Regency GP LLC, the Partnership s managing general partner. Pursuant to the Partnership Agreement, the managing general partner receives a monthly reimbursement for all direct and indirect expenses that it incurs on behalf of the Partnership. Reimbursements of $6,049,000 and $2,876,000 were recorded in the Partnership s financial statements during three months ended March 31, 2007 and 2006 as operating expenses or general and administrative expenses, as appropriate.

The Partnership made cash distributions of $7,934,000 and $4,752,000 during the three months ended March 31, 2007 and 2006 to HM Capital Partners and affiliates as a result of their ownership of a portion of the Partnerships common and subordinated units, and their ownership of the general partner interest.

Concurrent with the closing of the Partnership s IPO in three months ended March 31, 2006, the Partnership paid $9,000,000 to an affiliate of HM Capital Partners to terminate a management services contract with a remaining tenor of 9 years.

8. Segment Information

The Partnership has two reportable segments: i) gathering and processing and ii) transportation. Gathering and processing involves the collection of raw natural gas from producer wells across the five operating regions aggregated for segment reporting purposes and transportation of it to a treating 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 then is 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.

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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.

	Gathering and Processing	Transportation	Corporate	Eliminations	Total
			(in thousands)		
External Revenue					
For the three months ended March 31, 2007	$177,119	$ 79,309	$	$	$ 256,428
For the three months ended March 31, 2006	163,866	67,400			231,266
Intersegment Revenue					
For the three months ended March 31, 2007		14,818		(14,818)	
For the three months ended March 31, 2006		8,470		(8,470)	
Cost of Gas and Liquids					
For the three months ended March 31, 2007	146,941	64,996			211,937
For the three months ended March 31, 2006	139,224	57,512			196,736
Segment Margin					
For the three months ended March 31, 2007	30,178	14,313			44,491
For the three months ended March 31, 2006	24,642	9,888			34,530
Operation and Maintenance					
For the three months ended March 31, 2007	9,115	1,810			10,925
For the three months ended March 31, 2006	8,298	1,147			9,445
Depreciation and Amortization					
For the three months ended March 31, 2007	7,885	3,250	292		11,427
For the three months ended March 31, 2006	6,010	2,987	172		9,169
Assets					
March 31, 2007	672,524	321,225	37,810		1,031,559

December 31, 2006	648,116	316,038	48,931	1,013,085
Investments in Unconsolidated Subsidiaries				
March 31, 2007				
December 31, 2006	5,616			5,616
Expenditures for Long-Lived Assets				
For the three months ended March 31, 2007	35,547	4,385	87	40,019
For the three months ended March 31, 2006	14,727	15,530	121	30,378

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

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	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
	(in thousands)	
Total Segment Margin (from above)	$ 44,491	$ 34,530
Operation and maintenance	(10,925)	(9,445)
General and administrative	(6,851)	(5,416)
Loss on sale of assets	(1,808)	
Management services termination fee		(9,000)
Depreciation and amortization	(11,427)	(9,169)
Operating Income	13,480	1,500
Interest expense, net	(14,885)	(8,001)
Other income and deductions, net	110	182
Net loss	$ (1,295)	$ (6,319)

9. Equity-Based Compensation

In December 2005, the compensation committee of the board of directors of the Partnership s managing general partner approved a 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. LTIP awards generally vest on the basis of one-third of the award each year. The options expire ten years after the grant date.

The fair value of each option award is estimated on the date of grant using the Black-Scholes Option Pricing Model. The following assumptions apply to the options granted for the periods presented.

	Three Months Ended March 31, 2007
Weighted average expected life (years)	4
Weighted average expected dividend per unit	$ 1.48
Weighted average grant date fair value of options	$ 1.34
Weighted average grant date fair value of restricted common units	$ 22.85
Weighted average risk free rate	4.6%
Weighted average expected volatility	16.0%
Weighted average expected forfeiture rate	11.0%

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. Upon the vesting and exercise of the common unit options, the Partnership intends to settle these obligations with common units on a net basis. Accordingly, the Partnership expects to recognize an aggregate of $11,702,000 of compensation expense related to the grants under LTIP.

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	17,000	27.40		
Exercised	(11,967)	20.00		
Forfeited or expired	(29,767)	21.77		
Outstanding at end of period	884,866	21.17	9.0	$ 4,591
Exercisable at end of period	199,567	20.02		

* Intrinsic value equals the closing market price of a unit less the option strike price, multiplied by the number of unit options outstanding as of the end of each period presented. Unit options with a strike price greater than the closing market price are excluded.

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Restricted (Non-Vested) Units	Units	Weighted Average Grant Date Fair Value
Outstanding at beginning of period	516,500	$21.06
Granted	191,000	27.70
Vested		
Forfeited or expired	(20,000)	21.24
Outstanding at end of period	687,500	22.90

10. Subsequent Events

Partner Distributions. On April 26, 2007, the Partnership declared a distribution of $0.38 per common and subordinated unit, payable on May 15, 2007 to unitholders of record at the close of business on May 8, 2007.

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 owns and operates 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 (Fashing Processing Plant), 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 $19,722,000, (2) the payment of $34,513,000 in cash and (3) the assumption of $6,255,000 of liabilities. The cash portion of the consideration is subject to customary post-closing adjustments and was financed out of the proceeds of the Partnership s revolving credit facility.

In connection with the Pueblo Acquisition, the Partnership entered into a Registration Rights Agreement (the Registration Rights Agreement) with the Members. The Registration Rights Agreement provides these persons with rights under the Securities Act of 1933 to register the offering and sale of the common units of the Partnership that were issued to the Members pursuant to the Stock Purchase Agreement.

Proposed sale of NGLs pipeline. In April 2007, the Partnership entered into a letter of intent to sell a 34 mile east Texas NGLs pipeline for $3,000,000. The Partnership expects to close this sale in the second quarter of 2007.

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Item 2. 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 unaudited condensed consolidated financial statements and notes included elsewhere in this document.

OVERVIEW

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

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

HOW WE EVALUATE OUR OPERATIONS

Our management uses a variety of financial and operational measurements to analyze our performance. We view these measures as important 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 pipelines, (2) our ability to compete for volumes from successful new wells in other areas and (3) our ability to obtain natural gas that has been released from other commitments. We routinely monitor producer activity in the areas served by our gathering and processing systems to pursue new supply opportunities.

To increase 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.

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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. The following table reconciles the non-GAAP financial measure, total segment margin, to its most directly comparable GAAP measure, net income (loss).

	Three Months Ended	
	March 31, 2007	March 31, 2006
	(in thousands)	
Net loss	$ (1,295)	$ (6,319)
Add (deduct):		
Operation and maintenance	10,925	9,445
General and administrative	6,851	5,416
Loss on sale of assets	1,808	
Management services termination fee		9,000
Depreciation and amortization	11,427	9,169
Interest expense, net	14,885	8,001
Other income and deductions, net	(110)	(182)
Total segment margin	$ 44,491	$ 34,530

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

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

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

§ the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make cash distributions to our unitholders and general partners;

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

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

EBITDA should not be considered as an alternative to net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP. EBITDA is the starting point in determining cash available for distribution, which is an important non-GAAP financial measure for a publicly traded master limited partnership. The following table reconciles the non-GAAP financial measure, EBITDA, to its most directly comparable GAAP measure, net loss and net cash flows provided by operating activities.

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	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
	(in thousands)	
Net cash flows provided by (used in) operating activities	$ 27,470	$ (471)
Add (deduct):		
Depreciation and amortization	(11,986)	(9,318)
Equity income	43	91
Risk management portfolio value changes	124	191
Loss on sale of assets	(1,808)	
Unit based compensation expenses	(1,103)	(314)
Changes in current assets and liabilities:		
Accounts receivable	1,959	(16,938)
Other current assets	(598)	(921)
Accounts payable and accrued liabilities	(5,220)	23,535
Accrued taxes payable	(203)	(273)
Interest payable	(11,918)	
Other current liabilities	1,504	(12)
Other assets	441	(2,515)
Other liabilities		626
Net loss	$ (1,295)	$ (6,319)
Add:		
Interest expense, net	14,885	8,001
Depreciation and amortization	11,427	9,169
EBITDA	$ 25,017	$ 10,851

CASH DISTRIBUTIONS

On April 26, 2007, the Partnership declared a distribution of $0.38 per common and subordinated unit, payable on May 15, 2007 to unitholders of record at the close of business on May 8, 2007.

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RESULTS OF OPERATIONS

Three Months Ended March 31, 2007 vs. Three Months Ended March 31, 2006

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

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006	Change	Percent
	(in thousands except percentages and volume data)			
Revenues	$ 256,428	$ 231,266	$ 25,162	11%
Cost of gas and liquids	211,937	196,736	15,201	8
Total segment margin (1)	44,491	34,530	9,961	29
Operation and maintenance	10,925	9,445	1,480	16
General and administrative	6,851	5,416	1,435	26
Loss on sale of assets	1,808		1,808	N/M
Management services termination fee		9,000	(9,000)	N/M
Depreciation and amortization	11,427	9,169	2,258	25
Operating income	13,480	1,500	11,980	799
Interest expense, net	(14,885)	(8,001)	6,884	86
Other income and deductions, net	110	182	(72)	(40)
Net loss	$ (1,295)	$ (6,319)	$ (5,024)	80%
System inlet volumes (MMbtu/d) (2)	1,133,844	861,989	271,855	32

(1) For reconciliation of total segment margin to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read Item 2. Management s Discussion and Analysis of Financial

Condition and Results of Operations How We Evaluate Our Operations.

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

N/M Not meaningful

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

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006	Change	Percent
	(in thousands except percentages and volume data)			
Segment Financial and Operating Data:				
Gathering and Processing Segment				
Financial data:				
Segment margin	$ 30,178	$ 24,643	$ 5,535	22%
Operation and maintenance	9,115	8,298	817	10
Operating data:				
Throughput (MMbtu/d)	729,218	423,593	305,625	72
NGL gross production (Bbls/d)	20,047	17,478	2,569	15
Transportation Segment				
Financial data:				
Segment margin	$ 14,313	$ 9,887	$ 4,426	45
Operation and maintenance	1,810	1,147	663	58
Operating data:				
Throughput (MMbtu/d)	704,458	438,396	266,062	61

Net Loss. Net loss for the three months ended March 31, 2007 decreased $5,024,000 compared with the three months ended March 31, 2006. The primary reasons for this decrease are an increase in total segment margin of $9,961,000, or 29 percent, primarily due to increased throughput volumes in the transportation segment, operations of two north Louisiana refrigeration plants in the gathering and processing segment in 2007 and the absence in 2007 of management services termination fees of $9,000,000 paid in 2006 in connection with our IPO. Partially offsetting the decrease in net loss were the following items:

§ An increase in interest expense, net of $6,884,000 primarily due to increased levels of borrowings used primarily to finance our growth capital projects;

§ an increase in depreciation and amortization of $2,258,000 primarily due to higher levels of depreciation from projects completed since March 31, 2006;

§ a loss on the sale of certain non-core assets of $1,808,000 in the three months ended March 31, 2007;

§ an increase in operation and maintenance expense of $1,480,000 primarily due to an unplanned outage in the transportation segment and organic growth in the gathering and processing segment; and

§ an increase in general and administrative expense of $1,435,000 primarily due to higher employee related expenses and increased expenses associated with our long-term incentive plan.

Segment Margin. Segment margin for the three months ended March 31, 2007 increased $9,961,000 compared with the three months ended March 31, 2006. This increase was attributable to an increase of $5,535,000 in gathering and processing segment margin and an increase of $4,426,000 in transportation segment margin, discussed below.

Gathering and processing segment margin increased to $30,178,000 for the three months ended March 31, 2007 from $24,643,000 for the three months ended March 31, 2006, an increase of $5,535,000, or 22 percent. The major components of this increase were as follows:

§ $2,610,000 attributable to the operations of the Elm Grove and Dubberly refrigeration plants in North Louisiana, which began operations in May 2006 and December 2006, respectively;

- § $1,531,000 attributable to the operation of the LaSalle County Phase II organic growth project in South Texas, which began operations in December 2006; and

- § $1,394,000 primarily attributable to increased throughput volumes in north Louisiana and south Texas, partially offset by lower unit margins in west Texas.

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Transportation segment margin increased to $14,313,000 for the three months ended March 31, 2007 from $9,887,000 for the three months ended March 31, 2006, an increase of $4,426,000, or 45 percent. The major components of this increase were as follows:

§ $4,765,000 attributable to an increase in throughput volumes;

§ $778,000 attributable to increased average gross margin per MMBtu of throughput; and partially offset by

§ lower margins of $1,117,000 from marketing activity generated by our merchant function.

Eastside Compressor Fire. On March 18, 2007, a fire occurred at the Eastside Compressor Station on our Regency Intrastate Pipeline system. Of the three compressor units in the station, one was damaged beyond repair, the second unit sustained reparable damage and the third was slightly damaged. The third unit was restored to service in less than 40 hours. We have installed two smaller surplus compressors and three rental compressors to the site which provides temporary compression horsepower to offset the loss of the second unit s capacity. The second unit is expected to be back in service by the end of May 2007 at which time we expect to return to normal operations. There were no personal injuries as a result of the incident. The replacement unit for the severely damaged compressor is not expected to be in service until late third or early fourth quarter of 2007. We are managing the system with existing compressors on other parts of the system and with careful gas management. The Louisiana Department of Environmental Quality has granted a request for an emissions variance for the temporary compressors. While preliminary estimates of property damage are in the range of $5,500,000 to $6,900,000, the equipment is fully insured, subject to a deductible of $250,000. To date, this incident has had no material adverse effect on our business. Through the expedited installation of temporary compression and the careful management of the system we have been able to mitigate and anticipate that we will be able to continue to mitigate any material disruption to our business. To date, we have not experienced any material adverse effect on our ability to maintain pre-incident levels of gas flow. If we are unable to do so, however, we maintain insurance that we believe will protect us against any materially adverse financial effect. Our business interruption insurance is subject to a deductible for losses and expenses incurred during the first 30 days following an incident which will include our costs of mobilizing and installing the temporary compressors and the cost of gas losses at the time of the incident, estimated at $850,000. The total estimated deductible is $1,100,000.

Operation and Maintenance. Operations and maintenance expense increased to $10,925,000 in the three months ended March 31, 2007 from $9,445,000 for the corresponding period in 2006, a 16 percent increase. This increase is the result of the following factors:

§ $463,000 of unplanned outage expense in the transportation segment in 2007 related to the eastside compressor fire discussed above;

§ $424,000 of increased employee related expenses primarily in the gathering and processing segment resulting from additional employees related to system expansion and employee annual pay raises;

§ $274,000 of increased consumable expenses primarily in the gathering and processing segment resulting from two of our north Louisiana refrigeration plants and additional compressor units put into service subsequent to March 31, 2006;

§ $237,000 of increased utility expense primarily in the gathering and processing segment resulting from two of our north Louisiana refrigeration plants put into service subsequent to March 31, 2006;

§ $184,000 of increased non-income taxes resulting from a higher property taxes associated with our transportation system in north Louisiana; and

§ $102,000 decrease in contractor expenses primarily in the gathering and processing segment resulting from the hiring of additional personnel discussed above.

General and Administrative. General and administrative expense increased to $6,851,000 in the three months ended March 31, 2007 from $5,416,000 for the same period in 2006, a 26 percent increase. The increase is primarily due to the following factors:

- § $789,000 of increased expenses associated with our long-term incentive plan that primarily relate to the issuance of restricted units in the three months ended March 31, 2007 and
- § $624,000 of increased employee related expenses resulting from hiring senior level personnel to assist us in achieving our strategic objectives.

Other. 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 IPO. In the three months ended March 31, 2007, we sold selected non-core pipelines, related rights of way and contracts located in south Texas for $5,340,000 in cash on March 31, 2007 and recorded a related charge of $1,808,000.

Depreciation and Amortization. Depreciation and amortization expense increased to $11,427,000 in the three months ended March 31, 2007 from $9,169,000 for the three months ended March 31, 2006, a 25 percent increase. The increase is due to higher depreciation expense of $1,724,000 from projects completed since March 31, 2006 and higher identifiable intangible asset amortization of $534,000 related to contracts acquired in July 2006.

Interest Expense, Net. Interest expense, net increased $6,884,000, or 86 percent, in the three months ended March 31, 2007 compared to the same period in 2006. Of this increase, $5,285,000 was attributable to increased levels of borrowings and $1,789,000 was attributable to higher interest rates partially offset by $190,000 of amortization from interest rate swap termination proceeds from other comprehensive income. The unamortized balance of interest rate swap termination proceeds in other comprehensive income at March 31, 2007 was $888,000.

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

Risk Management Activities. In order to protect ourselves from commodity and interest rate risk, we pursue hedging activities to minimize those risks. These hedging activities rely upon forecasts of our expected operations and financial structure over the next three years. If our operations or financial structure are significantly different from these forecasts, we could be subject to adverse financial results as a result of these hedging activities. We mitigate this potential exposure by retaining an operational cushion between our forecasted transactions and the level of hedging activity executed. We monitor and review hedging positions regularly. We elected hedge accounting under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities , as amended, for all of our swap contracts but not for our crude oil put options. Accordingly, we record the unrealized changes in fair value in other comprehensive income (loss) to the extent the hedges are 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 and Cost Capitalization. Our assets consist primarily of natural gas gathering pipelines, processing plants, and transmission pipelines. We capitalize all construction-related direct labor and material costs, as well as indirect construction costs. Indirect construction costs include general engineering and the costs of funds used in construction. Capitalized interest represents the cost of funds used to finance the construction of new facilities and is expensed over the life of the constructed asset through the recording of depreciation expense. We capitalize the costs of renewals and betterments that extend the useful life, while we expense the costs of repairs, replacements and maintenance projects as incurred.

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

Equity Based Compensation. The fair value of each option award is estimated on the date of grant using the Black-Scholes Option Pricing Model. For information as to the assumptions applicable to options granted during the quarter ended March 31, 2007, see note 9 of Notes to Unaudited Condensed Consolidated Financial Statements.

OTHER MATTERS

Legal. Blackbrush Oil & Gas LLC, owned by an affiliate of HM Capital that was the seller in our acquisition of TexStar Field Services, L.P., and certain of its subsidiaries are defendants in a wrongful death action styled *Takas v. Strait Energy Services LLC et al.* brought in state district court in Jim Wells County, Texas. The claim for both actual and punitive damages is made on behalf of the wife of the driver of a tractor trailer truck who was killed when the truck was struck by a train at a railway crossing. The truck was owned by a subcontractor working on, and was enroute to, a construction site relating to a pipeline owned by an entity that was then a subsidiary of TexStar. This accident occurred on July 15, 2005, prior to our acquisition of TexStar on August 15, 2006. We have been advised by representatives of Blackbrush that the entity that owned the pipeline, which is now our subsidiary (Regency Frio NewLine LP), is likely to be named as a defendant in the litigation as a result of Blackbrush s reply to the complaint. We have notified our insurance carrier regarding this matter, and we do not expect it to have a material adverse effect on our financial condition or our results of operations.

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

Escrow Payable. At March 31, 2007, $5,848,000 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 Regency LLC Predecessor 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, Regency LLC Predecessor 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. Upon satisfactory completion of the remediation by El Paso, the amount held in escrow will be released. These contractual rights of Regency LLC Predecessor were continued by the Partnership.

Environmental. Waha Phase I. 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 estimated potential environmental remediation costs at specific locations were $1,900,000 to $3,100,000. No governmental agency has required that the Partnership undertakes 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.

Regulatory Environment. In August 2005, Congress enacted and the President signed the Energy Policy Act of 2005. With respect to the oil and gas industry, the new legislation focuses on the exploration and production sector, interstate pipelines, and refinery facilities. In many cases, the Act requires action by various government agencies over the near to mid-term. Management is unable to determine what impact, if any, the Act will have on its operations and cash flows.

LIQUIDITY AND CAPITAL RESOURCES

We expect our sources of liquidity to include:

§ cash generated from operations;

§ borrowings under our credit facility;

§ debt offerings; and

§ issuance of additional partnership units.

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

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 accounts receivable and accounts payable which settle over a much shorter span of time. When our derivative positions are settled, we expect an offsetting physical transaction, and, as a result, we do not expect risk management assets and liabilities to affect our ability to pay bills as they come due.

Our working capital deficit increased by $9,767,000 from December 31, 2006 to March 31, 2007 primarily due to the following:

§ An increase in interest payable of $11,918,000 due to interest accruals on our senior notes borrowings with payments due each June 15th and December 15th as compared to monthly interest payments on borrowings under our credit facility;

§ a net increase of $7,968,000 in liabilities from risk management activities primarily due to an increase in the commodity prices we expect to pay (index prices) on our outstanding swaps as compared to the commodity prices we will receive upon settlement of our swaps; offset by

§ a net decrease in net accounts receivable and accounts payable of $10,518,000 due the timing of receipts and payments.

Cash Flows from Operations. Net cash flows provided by operating activities increased $27,941,000 for the three months ended March 31, 2007 as compared to the three months ended March 31, 2006. Net loss decreased $5,024,000 from 2006 to 2007 primarily due to increased operating income of $11,980,000 offset by an increase in interest expense of $6,884,000 due to higher average outstanding debt balances. For the reason indicated above, cash flows for interest payable increased $11,918,000 due to interest accruals on our senior notes. Cash flows from accounts receivable and accounts payable and accrued liabilities decreased $9,858,000 due to the timing of receipts and payments.

Cash Flows from Investing Activities. Net cash flows used in investing activities increased $16,513,000, or 54 percent, in the three months ended March 31, 2007 compared to the three months ended March 31, 2006. The increase is primarily due to higher growth and maintenance capital expenditures discussed in Capital Requirements.

Cash Flows from Financing Activities. Net cash flows provided by financing activities decreased $12,165,000, or 39 percent, in the three months ended March 31, 2007 compared to the three months ended March 31, 2006 primarily due to (1) an increase in borrowings under our credit facility of $11,275,000 used primarily for growth capital projects; (2) a decrease of $8,977,000 related to IPO proceeds received in 2006 not received in 2007; and (3) an increase in partner distributions of $14,620,000 as there were no partner distributions paid in the quarter ended March 31, 2006.

Capital Requirements

We categorize our capital expenditures as either:

§ Growth capital expenditures, which are made to acquire additional assets to increase our business, to expand and upgrade existing systems and facilities or to construct or acquire similar systems or facilities; or

§ Maintenance capital expenditures, which are made to replace partially or fully depreciated assets, to maintain the existing operating capacity of our assets and to extend their useful lives or to maintain existing system volumes and related cash flows.

Growth Capital Expenditures. In the three months ended March 31, 2007, we incurred $37,348,000 of growth capital expenditures. Growth capital expenditures primarily relate to growth capital projects listed below and our acquisition of the outstanding interest in the Palafox Joint Venture that we did not own (50 percent) for $5,000,000 in February 2007.

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

- § Re-build and activate an existing nitrogen rejection unit at our Eustace Processing Plant;
- § Constructing 20 miles of 10 inch diameter pipeline, which will connect the Fashing Processing Plant to our Tilden Processing Plant in south Texas;
- § Constructing 31 miles of 12 inch diameter pipeline in south Texas; and
- § Electrification and adding an acid gas injection well at our Tilden Processing Plant.

Maintenance Capital Expenditures. In the three months ended March 31, 2007, we incurred $864,000 of maintenance capital expenditures. Maintenance capital expenditures primarily consist of compressor and equipment overhauls, as well as new well connects to our gathering systems, which replace volumes from naturally occurring depletion of wells already connected.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are a net seller of NGLs, and as such our financial results are exposed to fluctuations in NGLs pricing. We have executed swap contracts settled against crude oil, ethane, propane, butane and natural gasoline market prices, supplemented with crude oil put options. We have hedged our expected exposure to declines in prices for NGLs, condensate and natural gas volumes produced for our account in the approximate percentages set forth below:

	2007	2008	2009
NGL	73%	71%	28%
Condensate	67%	65%	65%
Natural Gas	58%	0%	0%

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 NGL swaps outstanding at March 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 (in thousands)
April 2007	December 2008	Ethane	1,246 (MBbls)	Index	$0.55-$0.655 ($/gallon)	$ (2,590)
April 2007	December 2009	Propane	1,112 (MBbls)	Index	$0.825-$1.10 ($/gallon)	(4,106)
		Butane	714 (MBbls)	Index	$1.025-$1.273 ($/gallon)	(2,731)
April 2007	December 2009					
April 2007	December 2009	Natural Gasoline	337 (MBbls)	Index	$1.22- $1.59 ($/gallon)	(1,399)
April 2007	December 2009	West Texas Intermediate Crude	654 (MBbls)	Index	$65.60-$68.38 ($/Bbl)	(1,048)
April 2007	December 2007	NYMEX Natural Gas	5,000 (MMBtu/d)	Index	$7.91 ($/MMBtu)	(493)
Total Fair Value						$ (12,367)

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Item 4. Controls and Procedures

Disclosure controls. At the end of the period covered by this report, an evaluation was performed under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of our managing general partner, of the effectiveness of the design and operation of our disclosure controls and procedures (as such terms are defined in Rule 13a 15(e) and 15d 15(e) of the Exchange Act). Based on that evaluation, management, including the Chief Executive Officer and Chief Financial Officer of our managing general partner, concluded that our disclosure controls and procedures were effective as of March 31, 2007 to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is properly recorded, processed, summarized and reported, within the time periods specified in the SEC s rules and forms.

Internal control over financial reporting. In anticipation of becoming subject to the provisions of Section 404 of the Sarbanes-Oxley Act of 2002, we initiated in early 2005 a program of documentation, implementation and testing of internal control over financial reporting. This program will continue through this year, culminating with our initial Section 404 certification and attestation in early 2008.

To the extent that we discover any matter in the design or operation of our system of internal control over financial reporting that might be considered to be a significant deficiency or a material weakness, whether or not considered reasonably likely to affect adversely our ability to record, process, summarize and report financial information properly, we report that matter to our independent registered public accounting firm and to the audit committee of our board of directors.

There have been no other changes in the Partnership s internal controls over financial reporting that has materially affected, or is reasonably likely to affect, the Partnership s internal controls over financial reporting.

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PART II OTHER INFORMATION

Item 1. Legal Proceedings

The information required for this item is provided in Note 6, Commitments and Contingencies, included in the notes to the unaudited condensed consolidated financial statements included under Part I, Item 1, which information is incorporated by reference into this item.

Item 1A. Risk Factors

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2006, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not the only risks facing our Partnership.

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 tangible assets and a lesser portion allocated to our intangible 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.

Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The information required for this item is provided in Note 10, Subsequent Events, included in the notes to the unaudited condensed consolidated financial statements included under Part I, Item 1, which information is incorporated by reference into this item.

Item 6. Exhibits

The exhibits below are filed as a part of this report:

Exhibit 12.1	Computation of Ratio of Earnings to Fixed Charges
Exhibit 31.1	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer
Exhibit 31.2	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer
Exhibit 32.1	Section 1350 Certifications of Chief Executive Officer
Exhibit 32.2	Section 1350 Certifications of Chief Financial Officer

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SIGNATURE

Pursuant to the requirements 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

/s/ Lawrence B. Connors

Lawrence B. Connors
Vice President of Accounting and Finance
(Duly
Authorized Officer and Chief Accounting
Officer)

May 14, 2007