Regency Energy Partners LP
Form 10-Q
August 14, 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 June 30, 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 40,470,969 common units and 19,103,896 subordinated units outstanding as of August 7, 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 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.

Part I Financial Information
Item 1. Financial Statements

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

	June 30, 2007 Unaudited	December 31, 2006
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 31,071	$ 9,139
Restricted cash	5,912	5,782
Accrued revenues and accounts receivable, net of allowance of $45 in 2007 and $181 in 2006	120,038	96,993
Related party receivables	201	755
Assets from risk management activities	381	2,126
Other current assets	4,944	5,279
Total current assets	162,547	120,074
Property, plant and equipment		
Gas plants and buildings	112,670	103,490
Gathering and transmission systems	576,972	529,776
Other property, plant and equipment	79,331	73,861
Construction-in-progress	103,621	85,277
Total property, plant and equipment	872,594	792,404
Less accumulated depreciation	(78,941)	(58,370)
Property, plant and equipment, net	793,653	734,034
Other assets:		
Intangible assets, net of amortization of $6,636 in 2007 and $4,676 in 2006	80,097	76,923
Long-term assets from risk management activities		1,674
Other, net of amortization of debt issuance costs of $2,049 in 2007 and $946 in 2006	16,566	17,212
Investments in unconsolidated subsidiaries		5,616
Goodwill	94,448	57,552
Total other assets	191,111	158,977
TOTAL ASSETS	$ 1,147,311	$ 1,013,085
LIABILITIES & PARTNERS CAPITAL		
Current Liabilities:		

Accounts payable, accrued cost of gas and liquids and accrued liabilities	$ 130,168	$ 117,254
Related party payables	2,624	280
Escrow payable	5,914	5,783
Accrued taxes payable	4,440	2,758
Liabilities from risk management activities	12,362	3,647
Interest payable	3,017	2,998
Other current liabilities	1,281	2,594
Total current liabilities	159,806	135,314
Long-term liabilities from risk management activities	5,982	145
Other long-term liabilities	16,115	269
Long-term debt	778,930	664,700
Commitments and contingencies		
Partners Capital:		
Common units (30,728,076 and 21,969,480 units authorized; 28,930,545 and 19,620,396 units issued and outstanding at June 30, 2007 and December 31, 2006)	173,761	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 June 30, 2007 and December 31, 2006)	25,041	43,240
General partner interest	5,219	5,543
Accumulated other comprehensive income (loss)	(17,543)	1,019
Total partners capital	186,478	212,657
TOTAL LIABILITIES AND PARTNERS CAPITAL	$ 1,147,311	$ 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 June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
REVENUES				
Gas sales	$ 195,870	$ 131,278	$ 363,253	$ 289,750
NGL sales	83,236	65,043	146,777	121,179
Gathering, transportation and other fees, including related party amounts of $431 and $784 in 2007 and $597 and $1,116 in 2006	17,884	14,730	37,763	27,434
Net realized and unrealized loss from risk management activities	(2,625)	(2,425)	(2,710)	(4,082)
Other	7,171	6,032	12,881	11,643
Total revenues	301,536	214,658	557,964	445,924
OPERATING COSTS AND EXPENSES				
Cost of gas and liquids, including related party amounts of $7,755 and $13,173 in 2007 and $753 and $1,266 in 2006	249,760	178,027	461,698	374,763
Operation and maintenance	11,008	8,382	21,932	17,827
General and administrative	19,293	6,923	26,144	12,339
Loss on sale of assets	532		2,340	
Management services termination fee				9,000
Depreciation and amortization	12,507	9,378	23,934	18,547
Total operating costs and expenses	293,100	202,710	536,048	432,476
OPERATING INCOME	8,436	11,948	21,916	13,448
Interest expense, net	(15,961)	(8,389)	(30,846)	(16,390)
Other income and deductions, net	173	201	283	383
INCOME (LOSS) BEFORE INCOME TAXES	(7,352)	3,760	(8,647)	(2,559)
Income tax expense	225		225	
NET INCOME (LOSS)	$ (7,577)	$ 3,760	$ (8,872)	$ (2,559)
Less: Net income from January 1-31, 2006				1,564
Net income (loss) for partners	$ (7,577)	$ 3,760	$ (8,872)	$ (4,123)

General partner s interest	(152)	75	(177)	(82)
Limited partners interest	(7,425)	3,685	(8,695)	(4,041)
Basic and diluted earnings per unit:				
Net income (loss) allocated to common units	$ (4,415)	$ 1,623	$ (4,808)	$ (1,802)
Weighted average number of common units outstanding	28,047,793	19,103,896	25,663,672	19,103,896
Income (loss) per common unit	$ (0.16)	$ 0.08	$ (0.19)	$ (0.09)
Distributions declared per unit	$ 0.38	$ 0.2217	$ 0.75	$ 0.5717
Net income (loss) allocated to subordinated units	$ (3,010)	$ 1,623	$ (3,887)	$ (1,762)
Weighted average number of subordinated units outstanding	19,103,896	19,103,896	19,103,896	19,103,896
Income (loss) per subordinated unit	$ (0.16)	$ 0.08	$ (0.20)	$ (0.09)
Distributions declared per unit	$ 0.38	$ 0.2217	$ 0.75	$ 0.5717
Net income (loss) allocated to Class B common units	$	$ 439	$	$ (477)
Weighted average number of Class B common units outstanding		5,173,189	1,314,733	5,173,189
Income (loss) per Class B common unit	$	$ 0.08	$	$ (0.09)
Distributions declared per unit	$	$	$	$
Net income (loss) allocated to Class C common units	$	$	$	$
Weighted average number of Class C common units outstanding			615,627	
Income (loss) per Class C common unit	$	$	$	$
Distributions declared per unit	$	$	$	$

See accompanying notes to unaudited condensed consolidated financial statements

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

	Three Months Ended		Six Months Ended	
	June 30, 2007	June 30, 2006	June 30, 2007	June 30, 2006
Net income (loss)	$ (7,577)	$ 3,760	$ (8,872)	$ (2,559)
Hedging losses reclassified to earnings	2,870	1,909	2,816	2,722
Net change in fair value of cash flow hedges	(8,933)	(10,504)	(21,378)	(6,077)
Comprehensive loss	$ (13,640)	$ (4,835)	$ (27,434)	$ (5,914)

See accompanying notes to unaudited condensed consolidated financial statements

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

	Units				Common	Class B	Class C	Subordinated	General Partner	Accumulated Other Comprehensive Income	
	Common	Class B	Class C	Subordinated	Unitholders	Unitholders	Unitholders	Unitholders	Interest	(Loss)	T
ce ber 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 mon	8,030,332	(5,173,189)	(2,857,143)		120,663	(60,671)	(59,992)				
ce of on units tions	751,597				19,724						1
ce of ed on units	546,000										
ures of ed on units	(23,333)										
se of on unit s	5,553										
ased nsation es					14,085						1
l . utions									515		
. utions					(18,119)			(14,328)	(662)		(3
s					(4,808)			(3,887)	(177)		(
					24			16			
dging y ified to gs										2,816	
ange in ue of ow										(21,378)	(2

ce									
0, 2007	28,930,545	19,103,896	$ 173,761	$	$	$ 25,041	$ 5,219	$ (17,543)	$ 18

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)

	Six Months Ended June 30, 2007	June 30, 2006
OPERATING ACTIVITIES		
Net loss	$ (8,872)	$ (2,559)
Adjustments to reconcile net loss to net cash flows provided by operating activities:		
Depreciation and amortization	24,626	18,975
Equity income	(43)	(220)
Risk management portfolio valuation changes	(591)	(811)
Loss on sale of assets	2,340	
Unit based compensation expenses	14,085	1,089
Cash flow changes in current assets and liabilities:		
Accrued revenues and accounts receivable	(20,878)	13,770
Other current assets	358	109
Accounts payable, accrued cost of gas and liquids and accrued liabilities	25,594	(11,743)
Accrued taxes payable	1,682	921
Interest payable	19	
Other current liabilities	(1,783)	(735)
Proceeds from early termination of interest rate swap		3,550
Other assets	(498)	2,382
Net cash flows provided by operating activities	36,039	24,728
INVESTING ACTIVITIES		
Capital expenditures	(65,911)	(61,290)
Acquisition of Pueblo Midstream Gas Corporation	(54,952)	
Investments in unconsolidated subsidiaries		(50)
Acquisition of investment in unconsolidated subsidiary, net of cash	(5,000)	96
Restricted cash		226
Proceeds from sale of assets	10,396	
Net cash flows used in investing activities	(115,467)	(61,018)
FINANCING ACTIVITIES		
Net borrowings under revolving credit facilities	114,230	39,400
Repayment under loan agreement		(350)
Partner contributions	515	
Partner distributions	(33,109)	(8,735)
Issuance of common units for acquisition of Pueblo Midstream Gas Corporation	19,724	
Debt issuance costs		(189)
Proceeds from IPO, net of issuance costs		256,953

Capital reimbursement to HM Capital		(195,757)
Working capital distribution to HM Capital		(48,000)
Capital reimbursement to HM Capital		(4,195)
Proceeds from exercise of over allotment option		26,163
Over allotment option proceeds to HM Capital		(26,163)
Net cash flows provided by financing activities	101,360	39,127
Net increase in cash and cash equivalents	21,932	2,837
Cash and cash equivalents at beginning of period	9,139	3,686
Cash and cash equivalents at end of period	$ 31,071	$ 6,523
Supplemental cash flow information		
Interest paid, net of amounts capitalized	$ 29,966	$ 15,824
Non-cash capital expenditures in accounts payable	11,943	9,225
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	

See accompanying notes to unaudited condensed consolidated financial statements

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). References to Regency Energy Partners, the Partnership, we, our, us and similar terms, refer to Regency Energy Partners LP and its subsidiaries. References to our general partner or the General Partner refer to Regency GP LP, the general partner of the Partnership. References to the Managing General Partner refer to Regency GP LLC, the general partner of the General Partner, which effectively manages the business and affairs of the Partnership.

On June 18, 2007, Regency GP Acquirer LP, an indirect subsidiary of General Electric Capital Corporation (GECC) acquired 91.3 percent of both the member interest in our Managing General Partner and the outstanding limited partner interests in our General Partner from Fund V and other affiliates of HM Capital Partners LLC (HM Capital). It also acquired from members of our management the remaining 8.7 percent of the member interest in the Managing General Partner and the remaining 8.7 percent of the outstanding limited partner interests in our General Partner. At the same time, Regency LP Acquirer LP, another indirect wholly owned subsidiary of GECC, acquired, in transactions with HM Capital and affiliates and members of our management, 17,763,809 of our outstanding subordinated units, of which 1,222,717 subordinated units were owned directly or indirectly by certain members of our management team.

In connection with these transactions, certain officers of the Managing General Partner agreed pursuant to a purchase and sale agreement (the Management Agreement) either to sell their interests in the General Partner for cash or exchange their interests in the General Partner for Class B limited partner interests in Regency GP Acquirer LP. At the same time, Regency GP Acquirer LP entered into a Subscription Agreement (the Subscription Agreement) with certain officers and other key employees pursuant to which Regency GP Acquirer LP agreed to sell to those officers and employees Class B limited partner interests proportional, in the aggregate, to the General Partner interests that it purchased for cash under the Management Agreement, as well as a limited number of subordinated units. As a consequence, it is anticipated that officers and key employees will acquire, pursuant to the Subscription Agreement, Class B Units of Regency GP Acquirer LP that entitle them to an indirect 8.2 percent ownership interest in the General Partner and will acquire 58,000 subordinated units.

GE Energy Financial Services is a unit of GECC which is an indirect wholly owned subsidiary of the General Electric Company. For simplicity, we refer to Regency GP Acquirer LP, Regency LP Acquirer LP and GE Energy Financial Services collectively as GE EFS. We refer to these acquisition transactions as the GE EFS Acquisition.

Affiliates of HM Capital have retained the 8,148,672 common units owned by them and agreed not to sell or otherwise distribute 3,406,099 common units for a period of one year and 4,692,417 common units for a period of six months. The Partnership has not recorded any adjustments to reflect GE EFS s acquisition of the HM Capital s interest in the Partnership or the related transactions.

While none of the Partnership, the General Partner or the Managing General Partner was a party to the GE EFS Acquisition, the Partnership has been advised that: (i) the aggregate purchase price paid by GE EFS to the HM Capital affiliate was $603,000,000 in cash; and (ii) the parties agreed to prorate any distributions that the Partnership may make on subordinated units and the general partner interest with respect to the second quarter of 2007.

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.

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The unaudited financial information as of June 30, 2007, and for the three months and six months ended June 30, 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 $86,733,000 at June 30, 2007 and $81,599,000 at December 31, 2006. Aggregate amortization expense for the three and six months ended June 30, 2007 was $986,000 and $1,987,000, respectively.

Income Taxes. The Partnership is generally not subject to income taxes, except as disclosed 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. In addition, the Partnership has wholly-owned subsidiaries that are subject to income tax and provides for income taxes using the 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 recorded a deferred tax liability of $9,182,000 as of June 30, 2007 related to depreciation of property, plant and equipment.

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.

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 No. 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 of the adoption of this standard on its financial position, results of operations or cash flows.

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 No. 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 of the adoption of this standard on its financial position, results of operations or cash flows that are not currently required to be measured at fair value.

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2. Income (Loss) per Limited Partner Unit

The following table shows the amounts used in computing basic and diluted limited partner income (loss) per unit.

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(in thousands except unit data and per unit data)			
Net income (loss) for partners	$ (7,577)	$ 3,760	$ (8,872)	$ (4,123)
Adjustments:				
General partner s interest	(152)	75	(177)	(82)
Limited partners interest in net income (loss)	$ (7,425)	$ 3,685	$ (8,695)	$ (4,041)
Net income (loss) allocated to common unitholders	$ (4,415)	$ 1,623	$ (4,808)	$ (1,802)
Weighted average common limited partner units basic	28,047,793	19,103,896	25,663,672	19,103,896
Common limited partners basic income (loss) per unit	$ (0.16)	$ 0.08	$ (0.19)	$ (0.09)
Weighted average common limited partner units basic	28,047,793	19,103,896	25,663,672	19,103,896
Dilutive effect of restricted units and common unit options		66,206		
Weighted average common limited partner units dilutive	28,047,793	19,170,102	25,663,672	19,103,896
Common limited partners dilutive earnings (loss) per unit	$ (0.16)	$ 0.08	$ (0.19)	$ (0.09)
Net income (loss) allocated to subordinated unitholders	$ (3,010)	$ 1,623	$ (3,887)	$ (1,762)
Weighted average subordinated limited partner units basic and diluted	19,103,896	19,103,896	19,103,896	19,103,896
Subordinated limited partners basic and diluted earnings (loss) per unit	$ (0.16)	$ 0.08	$ (0.20)	$ (0.09)
Net income (loss) allocated to Class B unitholders	$	$ 439	$	$ (477)
Weighted average Class B common units outstanding *		5,173,189	1,314,733	5,173,189
Class B common limited partners basic and diluted earnings (loss) per unit	$	$ 0.08	$	$ (0.09)
Net income (loss) allocated to Class C unitholders	$	$	$	$
Weighted average Class C common units outstanding *			615,627	

Class C common limited partners basic and diluted earnings (loss) per unit	$	$	$	$
Potentially dilutive securities excluded from diluted loss per unit:				
Restricted common units	355,000		355,000	432,500
Common unit options	868,568		868,568	731,500

* Converted into common units during the three months ended March 31, 2007.

Loss per unit for the six months ended June 30, 2006 reflects only the five 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.

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 distributions earned during that period. Since the Class B common units were deemed to be outstanding for the three and six months ended June 30, 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. 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.

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 one-time 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

$532,000. 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 to gathering and transmission systems and the related obligations under capital lease.

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 to acquire all the outstanding equity of Pueblo Midstream Gas Corporation, a Texas corporation (Pueblo) (the Pueblo Acquisition). Pueblo owned and operated natural gas gathering, treating and processing assets located in south Texas. These assets consist 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 $19,724,000 and (2) the payment of $34,844,000 in cash, exclusive of outstanding Pueblo liabilities of $9,822,000 and certain working capital amounts acquired of $384,000. 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 of $64,774,000 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	$ 384
Gas plants and buildings	8,994
Gathering and transmission systems	13,078
Other property, plant and equipment	180
Intangible assets subject to amortization (contracts)	5,242
Goodwill	36,896
Total assets acquired	$ 64,774
Current liabilities	(330)
Long-term liabilities	(9,492)
Net assets acquired	$ 54,952

The final purchase price allocation, which management expects to complete by December 31, 2007, may differ from the above estimates. In connection with the Pueblo Acquisition, the Partnership recorded $9,182,000 in deferred tax liabilities for differences between the book and tax basis for long-lived assets.

The following unaudited pro forma financial information has been prepared as if the acquisition of Pueblo had occurred at the beginning of 2006. 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.

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	Pro Forma Results for the period from April 1, 2006 through June 30, 2006	Pro Forma Results for the period from January 1, 2006 through June 30, 2006	Pro Forma Results for the period from January 1, 2007 through June 30, 2007
	(in thousands except earnings (loss) per unit data)		
Revenue	$218,511	$ 453,630	$ 561,685
Net income (loss)	3,774	(2,530)	(8,563)
Basic and diluted earnings (loss) per common unit	0.10	(0.10)	(0.18)
Basic and diluted earnings (loss) per subordinated unit	0.09	(0.10)	(0.19)
Basic and diluted earnings (loss) per Class B common unit	0.09	(0.10)	
Basic and diluted earnings (loss) per Class C common unit			

In connection with the Pueblo Acquisition, the Partnership entered into a Registration Rights Agreement (the Registration Rights Agreement) with the sellers. 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 sellers pursuant to the Stock Purchase Agreement.

4. Risk Management Activities

As of June 30, 2007, the Partnership s hedging positions reduce exposure to variability of future commodity prices through 2009. The hedging positions through 2008 have been designated and accounted for as SFAS No. 133 cash flow hedges. The net fair value of the Partnership s risk management activities constituted a liability of $17,963,000 as of June 30, 2007. The Partnership expects to reclassify $11,537,000 of hedging losses into revenues or interest expense, net from accumulated other comprehensive income (loss) in the next twelve months. The Partnership has determined that ineffectiveness for certain hedges is immaterial. In the six months ended June 30, 2007, we recognized immaterial gains related to hedged forecasted transactions that did not occur by the end of the originally specified period.

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. A portion of this amount was reclassified from accumulated other comprehensive income (loss) to interest expense, net over the originally projected period (i.e., April 2007 through March 2009) of the hedged forecasted transaction or when it is determined the hedged forecasted transaction is probable of not occurring. The Partnership reclassified $111,000 and $301,000 from accumulated other comprehensive income (loss), reducing interest expense, net in the three and six months ended June 30, 2007, respectively.

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5. Long-Term Debt

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

	June 30, 2007	December 31, 2006
	(in thousands)	
Senior notes	$ 550,000	$ 550,000
Term loans	50,000	50,000
Revolving loans	178,930	64,700
Total	778,930	664,700
Less: current portion		
Long-term debt	$ 778,930	$ 664,700
Availability		
Total credit facility limit	$ 300,000	$ 300,000
Term loans	(50,000)	(50,000)
Revolver loans	(178,930)	(64,700)
Letters of credit	(21,802)	(5,183)
Total available	$ 49,268	$ 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 8.64 percent and 7.21 percent for the six months ended June 30, 2007 and 2006, respectively, and 8.54 percent and 7.26 percent for the three months ended June 30, 2007 and 2006, respectively. The outstanding balances of the senior notes bear interest at a fixed rate of 8.375 percent.

During the months preceding the GE EFS Acquisition, the Partnership deferred plans for an equity offering. As a result, the Partnership became concerned that at June 30, 2007, the Partnership s leverage and interest coverage ratios might be out of compliance with financial covenants in the credit facility. Accordingly, the Partnership sought and obtained a waiver prior to and for the measurement period ending June 30, 2007. At June 30, 2007, the Partnership was in compliance with the covenants of the credit facility and the 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 (BBOG), 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. One of our subsidiaries (Regency Frio NewLine LP), has now been named as a defendant in the litigation. We have retained counsel to file responses, and notified our insurance carrier regarding this matter. 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 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 June 30, 2007, $5,912,000 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, RGS 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.

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 estimated potential environmental remediation costs at specific locations 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.

7. Related Party Transactions

Subsequent to the GE EFS Acquisition, HM Capital continues to hold over ten percent of the Partnership s outstanding units, and accordingly, HM Capital and its affiliates are considered to be a related party. BBOG 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 to the Partnership. All of the Partnership s related party receivables, payables, revenues and expenses as disclosed in the unaudited condensed consolidated financial statements relate to BBOG. BlackBrush Energy, Inc., a wholly owned subsidiary of HM Capital, subleases office space to the Partnership for which it paid $40,000 and $80,000 in the three and six months ended June 30, 2007.

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 $7,189,000 and $3,438,000 were recorded in the Partnership s financial statements during three months ended June 30, 2007 and 2006, respectively, and reimbursements of $13,238,000 and $6,314,000 were recorded in the Partnership s financial statements during the six months ended June 30, 2007 and 2006 as operating expenses or general and administrative expenses, as appropriate.

The Partnership made cash distributions of $16,152,000 and $4,752,000 during the six months ended June 30, 2007 and 2006 to HM Capital and affiliates as a result of their ownership in the Partnership. 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 hydrocarbons from producer wells across the five operating regions and transportation of it 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 then is transported to market separately from the natural gas liquids. The Partnership aggregates the

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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.

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	Gathering and Processing	Transportation	Corporate	Eliminations	Total
			(in thousands)		
External Revenue					
For the three months ended June 30, 2007	$212,667	$ 88,869	$	$	$ 301,536
For the three months ended June 30, 2006	147,762	66,896			214,658
For the six months ended June 30, 2007	389,786	168,178			557,964
For the six months ended June 30, 2006	311,628	134,296			445,924
Intersegment Revenue					
For the three months ended June 30, 2007		33,183		(33,183)	
For the three months ended June 30, 2006		5,175		(5,175)	
For the six months ended June 30, 2007		48,001		(48,001)	
For the six months ended June 30, 2006		13,645		(13,645)	
Cost of Gas and Liquids					
For the three months ended June 30, 2007	174,260	75,500			249,760
For the three months ended June 30, 2006	121,848	56,179			178,027
For the six months ended June 30, 2007	321,202	140,496			461,698
For the six months ended June 30, 2006	261,072	113,691			374,763
Segment Margin					
For the three months ended June 30, 2007	38,407	13,369			51,776
For the three months ended June 30, 2006	25,914	10,717			36,631
For the six months ended June 30, 2007	68,584	27,682			96,266
For the six months ended June 30, 2006	50,556	20,605			71,161
Operation and Maintenance					
For the three months ended June 30, 2007	9,519	1,489			11,008
For the three months ended June 30, 2006	7,280	1,102			8,382
For the six months ended June 30, 2007	18,633	3,299			21,932
	15,578	2,249			17,827

For the six months ended June 30, 2006					
Depreciation and Amortization					
For the three months ended June 30, 2007	8,846	3,358	303		12,507
For the three months ended June 30, 2006	6,102	3,072	204		9,378
For the six months ended June 30, 2007	16,731	6,607	596		23,934
For the six months ended June 30, 2006	12,112	6,059	376		18,547
Assets					
June 30, 2007	746,388	338,060	62,863		1,147,311
December 31, 2006	648,116	316,038	48,931		1,013,085
Investments in Unconsolidated Subsidiaries					
June 30, 2007					
December 31, 2006	5,616				5,616
Expenditures for Long-Lived Assets					
For the six months ended June 30, 2007	120,653	4,800	410		125,863
For the six months ended June 30, 2006	37,569	22,865	856		61,290

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

	Three Months Ended		**Six Months Ended**	
	June 30, 2007	**June 30, 2006**	**June 30, 2007**	**June 30, 2006**
	(in thousands)			
Total segment margin	$ 51,776	$ 36,631	$ 96,266	$ 71,161
Operation and maintenance	(11,008)	(8,382)	(21,932)	(17,827)
General and administrative	(19,293)	(6,923)	(26,144)	(12,339)
Management services termination fee				(9,000)
Loss on sale of assets	(532)		(2,340)	
Depreciation and amortization	(12,507)	(9,378)	(23,934)	(18,547)
Operating income	8,436	11,948	21,916	13,448
Interest expense, net	(15,961)	(8,389)	(30,846)	(16,390)
Other income and deductions, net	173	201	283	383
Income tax expense	(225)		(225)	
Net income (loss)	$ (7,577)	$ 3,760	$ (8,872)	$ (2,559)

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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. All outstanding, unvested LTIP awards at the time of the GE EFS Acquisition vested upon the change of control of the managing general partner. As a result, the Partnership recorded a one-time charge of $11,928,000 during the three months ended June 30, 2007. The Partnership recorded in general and administrative expense LTIP expense of $12,983,000 and $14,085,000 for the three and six months ended June 30, 2007, respectively. LTIP awards made prior to the GE EFS Acquisition generally vested on the basis of one-third of the award each year while 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.

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 during the periods presented.

	Three Months Ended		Six Months Ended	
	June 30, 2007	June 30, 2006	June 30, 2007	June 30, 2006
Weighted average expected life (years)	4	4	4	4
Weighted average expected dividend per unit	$1.52	$ 1.40	$1.51	$ 1.40
Weighted average grant date fair value per option	$2.50	$ 1.52	$2.31	$ 1.20
Weighted average risk free rate	4.6%	4.25%	4.6%	4.25%
Weighted average expected volatility	16.0%	15.0%	16.0%	15.0%
Weighted average expected forfeiture rate	11.0%	5.0%	11.0%	5.0%

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 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 $9,978,000 of compensation expense related to the grants under LTIP ratably over the future vesting period.

The common unit options and restricted (non-vested) common units activity for the six months ended June 30, 2007 are as follows:

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	(20,634)	20.30		$ 158
Forfeited or expired	(41,898)	21.85		
Outstanding at end of period	868,568	21.19	8.7	10,417
Exercisable at end of period	868,568	21.19	8.7	10,417

* Intrinsic value equals the closing market price of a unit at

period end 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 at period end are excluded.

The weighted average grant date fair value of options granted in the six months ended June 30, 2007 was $50,000.

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Restricted (Non-Vested) Common Units	Units	Weighted Average Grant Date Fair Value
Outstanding at beginning of period	516,500	$ 21.06
Granted	546,000	30.22
Vested	(684,167)	22.91
Forfeited or expired	(23,333)	21.07
Outstanding at end of period	355,000	31.58
Aggregate intrinsic value of outstanding at end of period (in thousands)		$11,211

10. Subsequent Events

Partner Distributions. On July 27, 2007, the Partnership declared a distribution of $0.38 per common and subordinated unit, payable on August 14, 2007 to unitholders of record at the close of business on August 7, 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 estimated offering expenses of $1,500,000. On July 31, 2007, the Partnership sold an additional 1,500,000 common units for $32.05 per unit as a part of the underwriters exercising 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). In July 2007, the Partnership reclassified $777,000 from accumulated other comprehensive loss as a reduction to interest expense, net.

On August 1, 2007, the Partnership initiated a notification process to its senior note holders to repurchase $192,500,000, or 35 percent of the amount outstanding, which will require the Partnership to pay an early redemption penalty of $16,122,000. Until the repurchase of the senior notes is complete, the Partnership may use the remaining net proceeds of $130,623,000 to fund working capital needs, growth capital projects or acquisitions.

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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. References to Regency Energy Partners, the Partnership, we, our, us and similar terms, refer to Regency Energy Partners LP a subsidiaries. References to our general partner or the General Partner refer to Regency GP LP, the general partner of the Partnership. References to the Managing General Partner refer to Regency GP LLC, the general partner of the General Partner, which effectively manages the business and affairs of the Partnership.

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). Hicks Muse Equity Fund V, L.P. (Fund V) and its affiliates, through HM Capital, controlled our general partner at the time. At the time, Fund V controlled HMTF Gas Partners through HM Capital. 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 to June 18, 2007).

On June 18, 2007, Regency GP Acquirer LP, an indirect wholly owned subsidiary of General Electric Credit Corporation (GECC), indirectly acquired 91.3 percent of both the member interest in our Managing General Partner and the outstanding limited partner interests in our General Partner from Fund V and other affiliates of HM Capital. It also indirectly acquired from members of our management the remaining 8.7 percent of the member interest in the Managing General Partner and the remaining 8.7 percent of the outstanding limited partner interests in our General Partner. At the same time, Regency LP Acquirer, another indirect wholly owned subsidiary of GECC, acquired, in transactions with HM Capital affiliates and members of our management, 17,763,809 of our outstanding subordinated units, of which 1,222,717 subordinated units were owned directly or indirectly by certain members of our management team. Members of our management team re-acquired or agreed to acquire interests in an affiliate of GE EFS that entitle them to an indirect 8.2 percent ownership interest in the Managing General Partner and the General Partner, as well as approximately 58,000 subordinated units.

GE Energy Financial Services is a unit of GECC which is an indirect wholly owned subsidiary of the General Electric Company. For simplicity, we refer to Regency GP Acquirer LP, Regency LP Acquirer LP and GE Energy Financial Services collectively as GE EFS. We refer to these acquisition transactions as the GE EFS Acquisition.

Affiliates of HM Capital have retained the 8,148,672 common units owned by them and have agreed not to sell or otherwise distribute 3,406,099 common units for a period of one year and 4,692,417 common units for a period of six months.

While none of the Partnership, the General Partner or the Managing General Partner was a party to the GE EFS Acquisition, the Partnership has been advised that: (i) the aggregate purchase price paid by GE EFS to the HM Capital was $603,000,000 in cash and (ii) the parties agreed to prorate any distributions that the Partnership may make on subordinated units and the general partner interest with respect to the second quarter of 2007.

In connection with the GE EFS Acquisition, certain officers of the Managing General Partner agreed pursuant to a purchase and sale agreement (the Management Agreement) either to sell their interests in the General Partner for cash or to exchange their interests in the General Partner for Class B limited partner interests in Regency GP Acquirer LP.

At the same time, Regency GP Acquirer LP entered into a Subscription Agreement (the Subscription Agreement) with certain officers and other key employees pursuant to which Regency GP Acquirer LP agreed to sell Class B limited partner interests proportional, in the aggregate, to the General Partner interests that it purchased for cash under the Management Agreement. As a consequence, it is anticipated that, following the closing under the Subscription Agreement, officers and key employees will own Class B Units of Regency GP Acquirer LP that entitle them to an indirect 8.2 percent ownership interest in the General Partner.

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 estimated offering expenses of $1,500,000. On July 31, 2007, the Partnership sold an additional 1,500,000 common units for $32.05 per unit 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). On August 1, 2007, the Partnership initiated a notification process to its senior note holders to repurchase $192,500,000, or 35 percent of the amount outstanding, which will require the Partnership to pay an early redemption penalty of $16,122,000. Until the repurchase of the senior notes is complete, the Partnership may use the remaining net proceeds of $130,623,000 to fund working capital needs, growth capital projects or acquisitions.

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.

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).

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	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(in thousands)			
Net income (loss)	$ (7,577)	$ 3,760	$ (8,872)	$ (2,559)
Add (deduct):				
Operation and maintenance	11,008	8,382	21,932	17,827
General and administrative	19,293	6,923	26,144	12,339
Management services termination fee				9,000
Loss on sale of assets	532		2,340	
Depreciation and amortization	12,507	9,378	23,934	18,547
Interest expense, net	15,961	8,389	30,846	16,390
Other income and deductions, net	(173)	(201)	(283)	(383)
Income tax expense	225		225	
Total segment margin	$ 51,776	$ 36,631	$ 96,266	$ 71,161

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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	Six Months Ended June 30, 2007	June 30, 2006
	(in thousands)	
Net cash flows provided by operating activities	$ 36,039	$ 24,728
Add (deduct):		
Depreciation and amortization	(24,626)	(18,975)
Equity income	43	220
Risk management portfolio valuation changes	591	811
Loss on sale of assets	(2,340)	
Unit based compensation expenses	(14,085)	(1,089)
Changes in current assets and liabilities:		
Accrued revenues and accounts receivable	20,878	(13,770)
Other current assets	(358)	(109)
Accounts payable, accrued cost of gas and liquids and accrued liabilities	(25,594)	11,743
Accrued taxes payable	(1,682)	(921)
Interest payable	(19)	
Other current liabilities	1,783	735
Proceeds from early termination of interest rate swap		(3,550)
Other assets	498	(2,382)
Net loss	$ (8,872)	$ (2,559)
Add:		
Interest expense, net	30,846	16,390
Depreciation and amortization	23,934	18,547
Income tax expense	225	
EBITDA	$ 46,133	$ 32,378

CASH DISTRIBUTIONS

On May 15, 2007, the Partnership paid a distribution of $0.38 per common and subordinated unit for the three months ended March 31, 2007. On July 27, 2007, the Partnership declared a distribution of $0.38 per common and subordinated unit for the three months ended June 30, 2007, payable on August 14, 2007 to unitholders of record at the close of business on August 7, 2007.

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RESULTS OF OPERATIONS

Three Months Ended June 30, 2007 vs. Three Months Ended June 30, 2006

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

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Change	Percent
	(in thousands except percentages and volume data)			
Revenues	$ 301,536	$ 214,658	$ 86,878	40%
Cost of gas and liquids	249,760	178,027	71,733	40
Total segment margin (1)	51,776	36,631	15,145	41
Operation and maintenance	11,008	8,382	2,626	31
General and administrative	19,293	6,923	12,370	179
Loss on the sale of assets	532		532	n/m
Depreciation and amortization	12,507	9,378	3,129	33
Operating income	8,436	11,948	(3,512)	(29)
Interest expense, net	(15,961)	(8,389)	(7,572)	90
Other income and deductions, net	173	201	(28)	(14)
Income (loss) before income taxes	(7,352)	3,760	(11,112)	(296)
Income tax expense	225		225	n/m
Net income (loss)	$ (7,577)	$ 3,760	$ (11,337)	(302)%
System inlet volumes (MMbtu/d) (2)	1,218,822	980,444	238,378	24

(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 June 30, 2007	June 30, 2006	Change	Percent
	(in thousands except volume data)			
Segment Financial and Operating Data:				
Gathering and Processing Segment				
Financial data:				
Segment margin	$ 38,407	$ 25,914	$ 12,493	48%
Operation and maintenance	9,519	7,280	2,239	31
Operating data:				
Throughput (MMbtu/d)	756,092	496,238	259,854	52
NGL gross production (Bbls/d)	20,967	16,972	3,995	24
Transportation Segment				
Financial data:				
Segment margin	$ 13,369	$ 10,717	$ 2,652	25
Operation and maintenance	1,489	1,102	387	35
Operating data:				
Throughput (MMbtu/d)	777,927	577,217	200,710	35

Net Income (Loss). Net loss of $7,577,000 for the three months ended June 30, 2007 compared to net income of $3,760,000 for the three months ended June 30, 2006, an $11,337,000 decline. An increase in total segment margin of $15,145,000 was primarily due to organic growth in the gathering and processing segment offset by:

§ an increase in general and administrative expense of $12,370,000 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 resulting from the change in control effected by the GE EFS Acquisition;

§ an increase of $7,572,000 in interest expense, net primarily due to increased levels of borrowings used primarily to finance our Pueblo Acquisition and growth capital projects;

§ an increase in operation and maintenance expense of $2,626,000 primarily due to organic growth in the gathering and processing segment; and

§ an increase in depreciation and amortization of $3,129,000 primarily due to higher levels of depreciation from projects completed since June 30, 2006.

Segment Margin. Total segment margin for the three months ended June 30, 2007 increased $15,145,000 compared with the three months ended June 30, 2006. This increase was attributable to an increase of $12,493,000 in gathering and processing segment margin and an increase of $2,652,000 in transportation segment margin as discussed below.

Gathering and processing segment margin increased to $38,407,000 for the three months ended June 30, 2007 from $25,914,000 for the three months ended June 30, 2006. The major components of this increase were as follows:

§ $3,558,000 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;

§ $3,362,000 associated with organic growth in east and south Texas;

§ $2,463,000 primarily attributable to other than described above increased throughput volumes in north Louisiana;

- § $2,271,000 attributable to volumes associated with our Como plant acquisition in July 2006; and
- § $1,364,000 attributable to the operation of the LaSalle County Phase II organic growth project in south Texas, which began operations in December 2006.

Transportation segment margin increased to $13,369,000 for the three months ended June 30, 2007 from $10,717,000 for the three months ended June 30, 2006. The major components of this increase were as follows:

- § $1,577,000 attributable to increased margins associated with our merchant marketing activities; and
- § $1,075,000 associated with increased throughput volumes, partially offset by reduced margin per unit.

Operation and Maintenance. Operations and maintenance expense increased to $11,008,000 in the three months ended June 30, 2007 from $8,382,000 for the corresponding period in 2006, a 31 percent increase. This increase is primarily the result of the following factors:

§ $940,000 of increased employee related expenses primarily in the gathering and processing segment resulting from the employment of additional employees as a result of organic growth and employee annual pay raises;

§ $633,000 of increased consumable expenses primarily in the gathering and processing segment resulting primarily from additional compression;

§ $479,000 of increased materials and parts expense primarily in the gathering and processing segment resulting mostly from materials and parts used at our processing plants and for additional compression;

§ $345,000 increase in contractor expenses primarily in the gathering and processing segment mostly related to contractor expense at Pueblo; and

§ $282,000 of increased property taxes associated with our transportation system in north Louisiana.

General and Administrative. General and administrative expense increased to $19,293,000 in the three months ended June 30, 2007 from $6,923,000 for the same period in 2006, a 179 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 resulting from the change in control effected by the GE EFS Acquisition;

§ $719,000 of increased employee related expenses primarily resulting from annual pay raises and hiring new employees to assist us in achieving our strategic objectives; and

§ $534,000 of increased expenses associated with our long-term incentive plan that primarily relates to the issuance of restricted units since July 1, 2006, exclusive of the one-time charge discussed above.

These factors were partially offset by the absence in 2007 of acquisition expenses related to our TexStar acquisition of $684,000 and TexStar management fees of $135,000. The acquisition costs were expensed because we accounted for the TexStar acquisition in a manner similar to a pooling of interests as the entities involved in the transaction were entities under common control.

Depreciation and Amortization. Depreciation and amortization expense increased to $12,507,000 in the three months ended June 30, 2007 from $9,378,000 for the three months ended June 30, 2006, a 33 percent increase. The increase is due to higher depreciation expense of $2,611,000 primarily from organic growth projects completed since June 30, 2006 and to a lesser extent depreciation expense from our Pueblo Acquisition in April 2007. Also contributing to the increase was higher identifiable intangible asset amortization of $518,000 primarily related to contracts acquired in July 2006.

Interest Expense, Net. Interest expense, net increased $7,572,000, or 90 percent, in the three months ended June 30, 2007 compared to the same period in 2006. Of this increase, $6,528,000 was attributable to increased levels of borrowings and $1,470,000 was attributable to higher interest rates partially offset by amortization from interest rate swap termination proceeds from accumulated other comprehensive income. The unamortized balance of interest rate swap termination proceeds in accumulated other comprehensive income at June 30, 2007 was $777,000.

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Six Months Ended June 30, 2007 vs. Six Months Ended June 30, 2006

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

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006	Change	Percent
	(in thousands except percentages and volume data)			
Revenues	$ 557,964	$ 445,924	$ 112,040	25%
Cost of gas and liquids	461,698	374,763	86,935	23
Total segment margin (1)	96,266	71,161	25,105	35
Operation and maintenance	21,932	17,827	4,105	23
General and administrative	26,144	12,339	13,805	112
Loss on sale of assets	2,340		2,340	n/m
Management services termination fee		9,000	(9,000)	n/m
Depreciation and amortization	23,934	18,547	5,387	29
Operating income	21,916	13,448	8,468	63
Interest expense, net	(30,846)	(16,390)	(14,456)	88
Other income and deductions, net	283	383	(100)	(26)
Income (loss) before income taxes	(8,647)	(2,559)	(6,088)	238
Income tax expense	225		225	n/m
Net loss	$ (8,872)	$ (2,559)	$ (6,313)	247%
System inlet volumes (MMbtu/d) (2)	1,176,568	916,218	260,350	28

(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.

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

	Six Months Ended June 30, 2007	June 30, 2006	Change	Percent
	(in thousands except volume data)			
Segment Financial and Operating Data:				
Gathering and Processing Segment				
Financial data:				
Segment margin	$ 68,584	$ 50,556	$ 18,028	36%
Operation and maintenance	18,633	15,578	3,055	20
Operating data:				
Throughput (MMbtu/d)	742,729	460,116	282,613	61
NGL gross production (Bbls/d)	20,510	17,224	3,286	19
Transportation Segment				
Financial data:				
Segment margin	$ 27,682	$ 20,605	$ 7,077	34
Operation and maintenance	3,299	2,249	1,050	47
Operating data:				
Throughput (MMbtu/d)	741,395	508,190	233,205	46

Net Loss. Net loss for the six months ended June 30, 2007 increased $6,313,000 compared with the six months ended June 30, 2006. An increase in total segment margin of $25,105,000 was primarily due to organic growth in the gathering and processing segment offset by:

§ an increase in interest expense, net of $14,456,000 primarily due to increased levels of borrowings used primarily to finance our Pueblo Acquisition and growth capital projects;

§ an increase in general and administrative expense of $13,805,000 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 resulting from the change in control effected by the GE EFS Acquisition and higher employee related expenses;

§ an increase in depreciation and amortization of $5,387,000 primarily due to higher levels of depreciation from organic growth projects completed since June 30, 2006;

§ an increase in operation and maintenance expense of $4,105,000 primarily due to increased employee related expenses, increased consumables expenses, an expense equal to our estimated thirty day insurance deductible relating to an unplanned outage in the transportation segment, higher property taxes in both our business segments; and

§ a loss on the sale of certain non-core assets of $2,340,000 in the six months ended June 30, 2007 and a one-time charge of $9,000,000 for the termination of two long-term management services contracts in connection with our IPO recorded in the six months ended June 30, 2006.

Segment Margin. Total segment margin for the six months ended June 30, 2007 increased $25,105,000 compared with the six months ended June 30, 2006. This increase was attributable to an increase of $18,028,000 in gathering and processing segment margin and an increase of $7,077,000 in transportation segment margin as discussed below.

Gathering and processing segment margin increased to $68,584,000 for the six months ended June 30, 2007 from $50,556,000 for the six months ended June 30, 2006. The major components of this increase were as follows:

§ $6,138,000 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;

§ $5,301,000 primarily attributable to other than described above organic growth in north Louisiana;

§ $4,416,000 attributable to volumes associated with our Como plant acquisition in July 2006;

§ $2,836,000 attributable to the operation of the LaSalle County Phase II organic growth project in South Texas, which began operations in December 2006;

§ $2,381,000 primarily attributable to other than described above organic growth in east and south Texas; and partially offset by

§ $1,238,000 attributable to year over year losses from risk management activities.

Transportation segment margin increased to $27,682,000 for the six months ended June 30, 2007 from $20,605,000 for the six months ended June 30, 2006. The major components of this increase were as follows:

§ $8,615,000 attributable to an increase in throughput volumes, partially offset by reduced margin per unit of $2,047,000 and

§ $460,000 of increased margins from our merchant marketing activities.

Operation and Maintenance. Operations and maintenance expense increased to $21,932,000 in the six months ended June 30, 2007 from $17,827,000 for the corresponding period in 2006, a 23 percent increase. This increase is the result of the following factors:

- § $1,364,000 of increased employee related expenses primarily in the gathering and processing segment resulting from the employment of additional employees as a result of organic growth and employee annual pay raises;
- § $908,000 of increased consumable expenses primarily in the gathering and processing segment primarily resulting from additional compression;
- § $627,000 of unplanned outage expense in the transportation segment in 2007 related to the Eastside compressor fire, which represents our estimated thirty day deductible;
- § $466,000 of increased higher property taxes associated with our transportation system in north Louisiana;
- § $419,000 of increased materials and parts expense primarily in the gathering and processing segment resulting mostly from materials and parts used at our processing plants and for additional compression; and
- § $418,000 of increased utility expense primarily in the gathering and processing segment resulting from two of our north Louisiana refrigeration plants, one placed in service in May 2006 and the other in December 2006.

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General and Administrative. General and administrative expense increased to $26,144,000 in the six months ended June 30, 2007 from $12,339,000 for the same period in 2006, a 112 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 resulting from the change in control effected by the GE EFS Acquisition;
- § $1,214,000 of increased employee related expenses resulting from pay raises and the employment of additional employees; and
- § $1,323,000 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.

Partially offsetting these increases in general and administrative expenses was the absence in 2007 of acquisition expenses related to our TexStar acquisition of $684,000.

Other. In the six months ended June 30, 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 six months ended June 30, 2007, we sold selected non-core pipelines, related rights of way and contracts located in the gathering and processing segment for $10,396,000 in cash and recorded a related charge of $2,340,000.

Depreciation and Amortization. Depreciation and amortization expense increased to $23,934,000 in the six months ended June 30, 2007 from $18,547,000 for the six months ended June 30, 2006, a 29 percent increase. The increase is due to higher depreciation expense of $4,336,000 primarily from organic growth projects completed since June 30, 2006 and to a lesser extent our April 2007 Pueblo Acquisition. Also contributing to the increase was higher identifiable intangible asset amortization of $1,051,000 primarily related to contracts acquired in July 2006.

Interest Expense, Net. Interest expense, net increased $14,456,000, or 88 percent, in the six months ended June 30, 2007 compared to the same period in 2006. Of this increase, $11,848,000 was attributable to increased levels of borrowings and $3,225,000 was attributable to higher interest rates partially offset by amortization from interest rate swap termination proceeds from accumulated other comprehensive income (loss). The unamortized balance of interest rate swap termination proceeds in accumulated other comprehensive income at June 30, 2007 was $777,000.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Information regarding the Partnership s critical accounting policies and estimates is included in Item 7 of the Partnership s Annual Report on Form 10-K for the year ended December 31, 2006.

OTHER MATTERS

Legal. Blackbrush Oil & Gas LLC (BBOG), 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. One of our subsidiaries (Regency Frio NewLine LP), has now been named as a defendant in the litigation. We have retained counsel to file responses, and notified our insurance carrier regarding this matter. 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 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 June 30, 2007, $5,912,000 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, we 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.

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 estimated potential environmental remediation costs at specific locations 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.

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.

As described above under Equity Offering, we sold to the public an aggregate of 11,500,000 common units in late July 2007 from which sale we received net proceeds of $353,832,000, exclusive of related proportional capital contributions by our general partner of $7,221,000.

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). In addition, we will redeem, after completion of the notice period, $192,500,000 in principal amount of our outstanding senior notes, which will require us to pay an early redemption penalty of $16,122,000. Until the repurchase of the senior notes is complete, we may use the remaining net proceeds of $130,623,000 to fund working capital needs, growth capital projects or acquisitions.

We believe our relationship with GE EFS increases our access to capital and enables us to pursue strategic opportunities that we may otherwise not be able to pursue. In addition, we believe we have sufficient liquidity under our credit facility to fund our near term growth capital requirements.

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 affected by changes in fair market value of our derivative positions to the extent 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 that settle over a much shorter span of time.

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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 surplus was $2,741,000 at June 30, 2007 compared to a working capital deficit of $15,240,000 at December 31, 2006. The increase in working capital of $17,981,000 is primarily due to:

§ an increase in cash and cash equivalents of $21,932,000 due to certain producer payments made after June 30, 2007;

§ a net increase in accrued revenues and accounts receivable and accounts payable, accrued cost of gas and liquids and accrued liabilities of $10,131,000 due the timing of receipts and payments; partially offset by

§ a net increase of $10,460,000 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; and

§ an increase in accrued taxes payable of $1,682,000 primarily due to anticipated increased levels of property tax in the transportation segment.

Cash Flows from Operations. Net cash flows provided by operating activities increased $11,311,000 for the six months ended June 30, 2007 as compared to the six months ended June 30, 2006. Cash generated from operations increased primarily due to increased segment margin.

Cash Flows from Investing Activities. Net cash flows used in investing activities increased $54,449,000, or 89 percent, in the six months ended June 30, 2007 compared to the six months ended June 30, 2006. The increase is primarily due to our Pueblo Acquisition ($54,952,000) in April 2007 and higher growth and maintenance capital expenditures discussed in Capital Requirements. Partially offsetting the increase in cash flows used in investing activities were $10,396,000 in proceeds from the sale of certain non-strategic assets.

Cash Flows from Financing Activities. Net cash flows provided by financing activities increased $62,233,000, or 159 percent, in the six months ended June 30, 2007 compared to the six months ended June 30, 2006 primarily due to (1) an increase in borrowings under our credit facility of $74,830,000 used primarily for our Pueblo Acquisition and growth capital projects; (2) a decrease of $9,000,000 related to IPO proceeds received in 2006 not received in 2007, which was subsequently used to terminate two management services contracts with an affiliate of HM Capital as a cash outflow from operations; and (3) an increase in partner distributions of $24,374,000 reflecting both an increase over the minimum quarterly distribution and the limited distributions made in the period following our IPO.

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 six months ended June 30, 2007, we incurred $55,609,000 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.

Our 2007 growth budget includes approximately $88,000,000 of currently identified organic growth capital expenditures. These growth capital expenditures are for more than 30 projects, of which the most significant are the following:

§ $16,200,000 for constructing a 40 mile, 10 inch diameter pipeline in our gathering and processing segment;

§

$12,000,000 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;

§ $9,400,000 to re-build and activate an existing nitrogen rejection unit at our Eustace Processing Plant;

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§ $8,100,000 for constructing 31 miles of 12 inch diameter pipeline in south Texas; and

§ $7,000,000 for the electrification and adding an acid gas injection well at our Tilden Processing Plant.

Maintenance Capital Expenditures. In the six months ended June 30, 2007, we incurred $3,236,000 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.

Contractual Obligations. In the three and six months ended June 30, 2007, we borrowed $80,830,000 and $114,230,000 under our revolving credit facility primarily for our Pueblo Acquisition and growth capital expenditures. During the three months ended June 30, 2007, we qualified for capital lease accounting on a NGL pipeline in east Texas with an obligation of $3,000,000, which we are amortizing over twenty years. During the three months ended June 30, 2007 we established a new purchase contractual obligation of $2,400,000 for a pipeline project in south Texas, which will be paid during the second half of 2007.

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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	78%	74%	29%
Condensate	74%	74%	74%
Natural Gas	67%	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 June 30, 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)
July 2007 December 2008	Ethane	1,116 (MBbls)	Index	$ 0.55-$0.673 ($/gallon)	$ 4,056
July 2007 December 2009	Propane	1,058 (MBbls)	Index	$ 0.825-$1.10 ($/gallon)	5,912
July 2007 December 2009	Butane	684 (MBbls)	Index	$ 1.025-$1.27 ($/gallon)	3,728
July 2007 December 2009	Natural Gasoline	387 (MBbls)	Index	$ 1.22-$1.59 ($/gallon)	2,201
July 2007 December 2009	West Texas Intermediate Crude	595 (MBbls)	Index	$ 65.60-$68.38 ($/Bbl)	2,447
July 2007 December 2007	NYMEX Natural Gas	5,000 (MMBtu/d)	Index	$ 7.91 ($/MMBtu)	(381)
Total Fair Value					$ 17,963

Interest Rate Risk

As of June 30, 2007, we had $228,930,000 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 $2,229,000.

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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 June 30, 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 have materially affected, or are 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 and in Park II, Item 1A. Risk Factors in our Quarterly Report on From 10-Q for the quarter ended March 31, 2007, which could materially affect our business, financial condition or results of operations. The risks described in our Annual Report on Form 10-K and Quarterly Report on Form 10-Q are not the only risks facing our Partnership.

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 current quarterly distribution. 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.

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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 United States Department of Transportation, or DOT, has adopted regulations requiring pipeline operators to develop integrity management programs for transportation pipelines 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 approximately $2,000,000 between 2007 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.

Restrictions in our credit agreement could limit our ability to make distributions upon the occurrence of certain events.

Our payment of principal and interest on our debt will reduce cash available for distributions on our common units. Our credit agreement limits our ability to make distributions upon the occurrence of the following events, among others:

§ failure to pay any principal, interest, fees or other amounts when due;

§ any representation or warranty proves to be false or misleading in any material respect;

§ failure to perform or otherwise comply with the covenants in the credit agreement or any loan document;

§ failure to pay any other material debt or failure to perform or otherwise to comply with the covenants of the agreements governing any material debt;

§ a bankruptcy or insolvency event involving us, our general partner or any of our subsidiaries;

§ the entry of, and failure to pay, one or more adverse judgments in excess of a specified amount against which enforcement proceedings are brought or that are not stayed pending appeal;

§ a change in control of us (waived by our lenders in the case of the GE EFS Acquisition);

§ the occurrence of certain events with respect to employee benefit plans subject to ERISA;

§ any security interest or lien in excess of a specified amount is no longer valid or in effect; and

§ any loan document is declared null and void or a proceeding is initiated to challenge the validity or enforceability of the loan document.

Any subsequent refinancing of our current debt or any new debt could have similar or more restrictive provisions. For more information regarding our credit agreement, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Requirements Fourth Amended and Restated Credit Agreement of our Annual Report on Form 10-K incorporated by reference herein.

Risks Related to Our Structure

GE EFS owns 29.8 percent as of August 7, 2007 of the limited partner units outstanding and controls our general partner, which has sole responsibility for conducting our business and managing our operations.

GE EFS owns 29.8 percent as of August 7, 2007 of the limited partner units outstanding and controls our General Partner. Although our General Partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the directors and officers of our General Partner have a fiduciary duty to manage our General Partner in a manner beneficial to its owner, GE EFS. Conflicts of interest may arise between GE EFS and its affiliates, including our General Partner, on the one hand, and us, on the other hand. In resolving these conflicts of interest, our General Partner may favor its own interests and the interests of its affiliates over our interests. These conflicts include, among others, the following situations:

- § neither our partnership agreement nor any other agreement requires GE EFS or its affiliates to pursue a business strategy that favors us;

- § our General Partner is allowed to take into account the interests of parties other than us, such as 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 by it and its affiliates are reimbursable by us;

§ our partnership agreement does not restrict our General Partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;

§ our General Partner intends to limit its liability regarding our contractual and other obligations; and

§ our General Partner controls the enforcement of obligations owed to us by our General Partner and its affiliates.

GE EFS and its affiliates may compete directly with us.

GE EFS and its affiliates are not prohibited from owning assets or engaging in businesses that compete directly or independently with us. GE EFS and its affiliates currently own various midstream assets and conduct midstream business that may potentially compete with us. In addition, GE EFS or its affiliates may acquire, construct or dispose of any additional midstream or other assets in the future, without any obligation to offer us the opportunity to purchase or construct or dispose of those assets.

Our partnership agreement limits our General Partner s fiduciary duties to our unitholders and restricts the remedies available to unitholders for actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty.

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

§ permits our General Partner to make a number of decisions in its individual capacity, as opposed to its capacity as our General Partner. This entitles our General Partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include the exercise of its limited call right, its voting rights with respect to the units it owns, its registration rights and its determination whether or not to consent to any merger or consolidation of the partnership;

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

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

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

§ provides that our General Partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the General Partner or those other persons acted in bad faith or engaged in fraud or willful misconduct.

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

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Tax Risks to Common Unitholders

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 (reduced to 29.8 percent after giving effect to the contemporaneous awards under our long-term incentive plan and our July 2007 equity offering), (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 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. Our termination would, among other things, result in the closing of our taxable year for all unitholders on June 18, 2007 and upon any future termination. Such a closing of the books could result in a significant deferral of depreciation deductions allowable in computing our taxable income. We anticipate that the impact of this termination to our unitholders will be an increased amount of taxable income as a percentage of the cash distributed to our unitholders. Although the amount of increase cannot be estimated because it depends upon numerous factors including the timing of the termination, the amount could be material. Moreover, 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. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be 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 determine that a termination occurred.

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 3, Acquisitions and Dispositions, 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
Exhibit 99.1	Regency GP LP Unaudited Condensed Consolidated Balance Sheet

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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)

August 13, 2007