Regency Energy Partners LP
Form 10-Q
August 11, 2008

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, 2008

OR

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

Commission File Number: 000-51757

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

DELAWARE	16-1731691
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1700 PACIFIC AVENUE, SUITE 2900 DALLAS, 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, a non-accelerated filer, or a smaller reporting company. See definition of "large accelerated filer, accelerated filer, and small reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

þ Large accelerated filer o Accelerated filer o Non-accelerated filer (Do not check if a smaller reporting company)
o Smaller reporting company

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 54,796,675 common units, 7,276,506 Class D common units, and 19,103,896 subordinated units outstanding as of August 4, 2008.

Introductory Statement

References in this report to the "Partnership," "we," "our," "us" and similar terms, when used in a historical context, refer to Regency Energy Partners LP, or the Partnership, and to Regency Gas Services LLC, all the outstanding member interests of which were contributed to the Partnership on February 3, 2006, and its subsidiaries. When used in the present tense or prospectively, these terms refer to the Partnership and its subsidiaries. We use the following definitions in this quarterly report on Form 10-Q:

Name	Definition or Description
ASC	ASC Hugoton LLC, an affiliate of GECC
Bbls/d	Barrels per day
Bcf	One billion cubic feet
Bcf/d	One billion cubic feet per day
BTU	A unit of energy needed to raise the temperature of one pound of water by one degree Fahrenheit
CDM	CDM Resource Management LLC
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
DOT	U.S. Department of Transportation
EIA	Energy Information Administration
EnergyOne	FrontStreet EnergyOne LLC
El Paso	El Paso Field Services, LP
EPA	Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FrontStreet	FrontStreet Hugoton LLC
GAAP	Accounting principles generally accepted in the United States
GE	General Electric Company
GE EFS	General Electric Energy Financial Services, a unit of GECC, combined with Regency GP Acquirer LP and Regency LP Acquirer LP
GECC	General Electric Capital Corporation, an indirect wholly owned subsidiary of GE
General Partner	Regency GP LP, the general partner of the Partnership, or Regency GP LLC, the general partner of Regency GP LP, which effectively manages the business and affairs of the Partnership
GSTC	Gulf States Transmission Corporation
HLPSA	Hazardous Liquid Pipeline Safety Act
IRS	Internal Revenue Service
LIBOR	London Interbank Offered Rate
MMbtu	One million BTUs
MMbtu/d	One million BTUs per day
MMcf	One million cubic feet
MMcf/d	One million cubic feet per day
MQD	Minimum Quarterly Distribution
Nexus	Nexus Gas Holdings, LLC
NOE	Notice of Enforcement
NGA	Natural Gas Act of 1938
NGLs	Natural gas liquids
NGPA	Natural Gas Policy Act of 1978
NGPSA	Natural Gas Pipeline Safety Act of 1968, as amended
NPDES	National Pollutant Discharge Elimination System
Nasdaq	Nasdaq Stock Market, LLC

NYMEX	New York Mercantile Exchange
OSHA	Occupational Safety and Health Act
Partnership	Regency Energy Partners LP
Pueblo	Pueblo Midstream Gas Corporation
RCRA	Resource Conservation and Recovery Act
RGS	Regency Gas Services LLC
RIGS	Regency Intrastate Gas LLC
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standard
Sonat	Southern Natural Gas Company
TCEQ	Texas Commission on Environmental Quality
Tcf	One trillion cubic feet
Tcf/d	One trillion cubic feet per day
TRRC	Texas Railroad Commission

Cautionary Statement about Forward-Looking Statements

Certain matters discussed in this report include “forward-looking” statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. Statements using words such as “anticipate,” “believe,” “intend,” “project,” “plan,” “expect,” “continue,” “estimate,” “goal,” “forecast,” “may” or similar expre identify forward-looking statements. Although we believe our forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, we can not give assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions including without limitation the following:

- changes in laws and regulations impacting the midstream and compression sectors of the natural gas industry;
- the level of creditworthiness of our counterparties and customers;
- our ability to access the debt and equity markets;
- our use of derivative financial instruments to hedge commodity and interest rate risks;
- the amount of collateral required to be posted from time to time in our transactions;
- changes in commodity prices, interest rates, demand for our services;
- weather and other natural phenomena;
- industry changes including the impact of consolidations and changes in competition;
- our ability to obtain required approvals for construction or modernization of our facilities and the timing of operations of 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.

Part1-Financial Information
Item 1. Financial Statements

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

		June 30, 2008 (Unaudited)		December 31, 2007*
ASSETS				
Current Assets:				
Cash and cash equivalents	$	29,985	$	32,971
Restricted cash		10,050		6,029
Trade accounts receivable, net of allowance of $242 in 2008 and $61 in 2007		29,303		16,487
Accrued revenues		200,078		117,622
Related party receivables		493		61
Assets from risk management activities		9,305		-
Other current assets		9,637		6,723
Total current assets		288,851		179,893
Property, plant and equipment				
Gas plants and buildings		138,688		134,300
Gathering and transmission systems		1,291,859		780,761
Other property, plant and equipment		149,127		105,399
Construction-in-progress		113,731		33,552
Total property, plant and equipment		1,693,405		1,054,012
Less accumulated depreciation		(181,480)		(140,903)
Property, plant and equipment, net		1,511,925		913,109
Other Assets:				
Intangible assets, net of accumulated amortization of $15,216 in 2008 and $8,929 in 2007		209,098		77,804
Long-term assets from risk management activities		9,362		-
Other, net of accumulated amortization of debt issuance costs of $3,869 in 2008 and $2,488 in 2007		18,075		13,529
Goodwill		265,784		94,075
Total other assets		502,319		185,408
TOTAL ASSETS	$	2,303,095	$	1,278,410
LIABILITIES & PARTNERS' CAPITAL				
Current Liabilities:				
Trade accounts payable	$	65,583	$	48,904

Accrued cost of gas and liquids		162,420		96,026
Related party payables		-		50
Escrow payable		10,050		6,029
Liabilities from risk management activities		76,016		37,852
Other current liabilities		24,711		9,397
Total current liabilities		338,780		198,258
Long-term liabilities from risk management activities		40,461		15,073
Other long-term liabilities		15,963		15,393
Long-term debt		1,162,500		481,500
Minority interest in consolidated subsidiary		7,464		4,893
Commitments and contingencies				
Partners' Capital:				
Common units (46,602,000 and 41,283,079 units authorized; 45,769,948 and 40,514,895 units issued and outstanding at June 30, 2008 and December 31, 2007)		562,458		490,351
Class D common units (7,276,506 units authorized, issued and outstanding at June 30, 2008)		223,015		-
Class E common units (4,701,034 units authorized, issued and outstanding at December 31, 2007)		-		92,962
Subordinated units (19,103,896 units authorized, issued and outstanding at June 30, 2008 and December 31, 2007)		(3,716)		7,019
General partner interest		18,798		11,286
Accumulated other comprehensive loss		(62,628)		(38,325)
Total partners' capital		737,927		563,293
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$	2,303,095	$	1,278,410

See accompanying notes to condensed consolidated financial statements

* Recast to reflect an acquisition accounted for in a manner similar to a pooling of interests.

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

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007 *	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007 *
REVENUES				
Gas sales	$ 362,769	$ 195,870	$ 599,462	$ 363,253
NGL sales	126,521	83,236	235,020	146,777
Gathering, transportation and other fees, including related party amounts of $935, $431, $1,926 and $784	70,175	19,196	132,161	39,074
Net realized and unrealized loss from risk management activities	(32,760)	(2,625)	(46,417)	(2,710)
Other	20,000	7,153	31,714	12,862
Total revenues	546,705	302,830	951,940	559,256
OPERATING COSTS AND EXPENSES				
Cost of sales, including related party amounts of $844, $7,755, $1,247 and $13,173	446,687	249,760	760,276	461,698
Operation and maintenance	32,516	11,972	61,361	22,897
General and administrative	13,925	19,093	24,809	25,944
Loss on asset sales, net	442	532	468	2,339
Management services termination fee	-	-	3,888	-
Transaction expenses	147	-	534	-
Depreciation and amortization	26,476	12,703	48,216	24,130
Total operating costs and expenses	520,193	294,060	899,552	537,008
OPERATING INCOME	26,512	8,770	52,388	22,248
Interest expense, net	(16,782)	(15,961)	(32,188)	(30,846)
Other income and deductions, net	132	170	332	282
Minority interest	69	(17)	(3)	(17)
INCOME (LOSS) BEFORE INCOME TAXES	9,931	(7,038)	20,529	(8,333)
Income tax expense (benefit)	(41)	225	209	225
NET INCOME (LOSS)	$ 9,972	$ (7,263)	$ 20,320	$ (8,558)
General partner's interest in current period net income (loss), including IDR	336	(152)	1,069	(177)
Beneficial conversion feature for Class C common units	-	-	-	1,385
Beneficial conversion feature for Class D common units	1,866	-	3,425	-
Limited partners' interest in net income (loss)	$ 7,770	$ (7,111)	$ 15,826	$ (9,766)

Basic and diluted earnings per unit:				
Amount allocated to common and subordinated units	$ 7,770	$ (7,425)	$ 15,826	$ (10,080)
Weighted average number of common and subordinated units outstanding	62,174,317	47,151,689	60,701,912	44,767,568
Income (loss) per common and subordinated unit	$ 0.12	$ (0.16)	$ 0.26	$ (0.23)
Distributions per unit	$ 0.42	$ 0.38	$ 0.82	$ 0.75
Amount allocated to Class B common units	$ -	$ -	$ -	$ -
Weighted average number of Class B common units outstanding	-	-	-	1,314,733
Income per Class B common unit	$ -	$ -	$ -	$ -
Distributions per unit	$ -	$ -	$ -	$ -
Amount allocated to Class C common units	$ -	$ -	$ -	$ 1,385
Total number of Class C common units outstanding	-	-	-	2,857,143
Income per Class C common unit due to beneficial conversion feature	$ -	$ -	$ -	$ 0.48
Distributions per unit	$ -	$ -	$ -	$ -
Amount allocated to Class D common units	$ 1,866	$ -	$ 3,425	$ -
Total number of Class D common units outstanding	7,276,506	-	7,276,506	-
Income per Class D common unit due to beneficial conversion feature	$ 0.26	$ -	$ 0.47	$ -
Distributions per unit	$ -	$ -	$ -	$ -
Amount allocated to Class E common units	$ -	$ 314	$ -	$ 314
Total number of Class E common units outstanding	4,701,034	4,701,034	4,701,034	4,701,034
Income per Class E common unit	$ -	$ 0.07	$ -	$ 0.07
Distributions per unit	$ -	$ 0.24	$ -	$ 0.24

See accompanying notes to condensed consolidated financial statements

* Recast to reflect an acquisition accounted for in a manner similar to a pooling of interests.

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

	Three Months Ended		Six Months Ended	
	June 30, 2008	June 30, 2007 *	June 30, 2008	June 30, 2007 *
Net income (loss)	$ 9,972	$ (7,263)	$ 20,320	$ (8,558)
Hedging amounts reclassified to earnings	15,166	2,870	25,602	2,816
Net change in fair value of cash flow hedges	(47,071)	(8,933)	(49,905)	(21,378)
Comprehensive loss	$ (21,933)	$ (13,326)	$ (3,983)	$ (27,120)

See accompanying notes to condensed consolidated financial statements

* Recast to reflect an acquisition accounted for in a manner similar to a pooling of interests.

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

	Six Months Ended	
	June 30, 2008	June 30, 2007 *
OPERATING ACTIVITIES		
Net income (loss)	$ 20,320	$ (8,558)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:		
Depreciation and amortization, including debt issuance cost amortization	49,598	24,823
Equity income and minority interest in earnings	-	(26)
Risk management portfolio valuation changes	20,582	(591)
Loss on asset sales	468	2,340
Unit based compensation expenses	1,839	14,085
Cash flow changes in current assets and liabilities:		
Trade accounts receivable and accrued revenues	(72,784)	(17,653)
Other current assets	(2,914)	365
Trade accounts payable, accrued cost of gas and liquids, and accrued liabilities	53,088	18,350
Other current liabilities	15,314	(41)
Other assets and liabilities	1,423	(498)
Net cash flows provided by operating activities	86,934	32,596
INVESTING ACTIVITIES		
Capital expenditures	(148,888)	(65,911)
Acquisitions	(577,345)	(35,228)
Acquisition of investment in unconsolidated subsidiary, net of $100 cash	-	(5,000)
Proceeds from asset sales	580	10,396
Net cash flows used in investing activities	(725,653)	(95,743)
FINANCING ACTIVITIES		
Net borrowings under revolving credit facilities	681,000	114,230
Partner contributions	7,663	6,244
Partner distributions	(52,317)	(34,309)
Proceeds from option exercises	2,700	-
Debt issuance costs	(3,313)	-
Net cash flows provided by financing activities	635,733	86,165

Net increase (decrease) in cash and cash equivalents		(2,986)		23,018
Cash and cash equivalents at beginning of period		32,971		11,932
Cash and cash equivalents at end of period	$	29,985	$	34,950
Supplemental cash flow information				
Interest paid, net of amounts capitalized	$	28,222	$	29,996
Income taxes paid		564		-
Non-cash capital expenditures in accounts payable		17,907		11,943
Non-cash capital expenditures for consolidation of investment in previously unconsolidated subsidiary		-		5,650
Non-cash capital expenditure upon entering into a capital lease obligation		-		3,000
Issuance of common units for an acquisition		219,590		19,724

See accompanying notes to condensed consolidated financial statements

* Recast to reflect an acquisition accounted for in a manner similar to a pooling of interests.

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

	Units									A
	Common	Class D	Class E	Subordinated	Common Unitholders	Class D Unitholders	Class E Unitholders	Subordinated Unitholders	General Partner Interest	Co
Balance - December 31, 2007 *	40,514,895	-	4,701,034	19,103,896	$ 490,351	$ -	$ 92,962	$ 7,019	$ 11,286	$
Issuance of Class D common units	-	7,276,506	-	-	-	219,590	-	-	-	
Issuance of restricted common units and option exercises, net of forfeitures	554,019	-	-	-	2,700	-	-	-	-	
Working capital adjustment on FrontStreet	-	-	-	-	-	-	(858)	-	-	
Conversion of Class E common units	4,701,034		(4,701,034)		92,104	-	(92,104)	-	-	
Unit based compensation expenses	-	-	-	-	1,839	-	-	-	-	
General partner contributions	-	-	-	-	-	-	-	-	7,663	
Partner distributions	-	-	-	-	(35,432)	-	-	(15,665)	(1,220)	
Net income	-	-	-	-	10,896	3,425	-	4,930	1,069	
Net hedging amounts reclassified to earnings	-	-	-	-	-	-	-	-	-	
Net change in fair value of cash flow hedges	-	-	-	-	-	-	-	-	-	
Balance - June 30, 2008	45,769,948	7,276,506	-	19,103,896	$ 562,458	$ 223,015	$ -	$ (3,716)	$ 18,798	$

See accompanying notes to condensed consolidated financial statements

*Recast to reflect an acquisition accounted for in a manner similar to a pooling of interests.

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, and its wholly owned and consolidated subsidiaries. The Partnership and its subsidiaries are engaged in the business of gathering, processing, contract compression, marketing, and transporting natural gas and NGLs. The Partnership operates and manages its business as three reportable segments: a) gathering and processing, b) transportation, and c) contract compression.

On January 7, 2008, the Partnership acquired all of the outstanding equity and minority interest (the "FrontStreet Acquisition") of FrontStreet from ASC and EnergyOne. FrontStreet owns a gas gathering system located in Kansas and Oklahoma, which is operated by a third party.

The total purchase price consisted of (a) 4,701,034 Class E common units of the Partnership issued to ASC in exchange for its 95 percent interest and (b) the payment of $11,752,000 in cash to EnergyOne in exchange for its five percent minority interest and the termination of a management services contract valued at $3,888,000. The Partnership financed the cash portion of the purchase price out of its revolving credit facility.

In connection with the FrontStreet Acquisition, the Partnership amended its Agreement of Limited Partnership to create the Partnership's Class E common units. The Class E common units have the same terms and conditions as the Partnership's common units, except that the Class E common units were not entitled to participate in earnings or distributions of operating surplus by the Partnership. The Class E common units were issued in a private offering conducted in accordance with the exemption from the registration requirements of the Securities Act of 1933 as afforded by Section 4(2) thereof. The Class E common units converted into common units on a one-for-one basis on May 5, 2008.

Because the acquisition of ASC's 95 percent interest is a transaction between commonly controlled entities (i.e., the buyer and the seller were each affiliates of GECC), the Partnership accounted for this portion of the acquisition in a manner similar to the pooling of interest method. Under this method of accounting, the Partnership reflected historical balance sheet data for both the Partnership and FrontStreet instead of reflecting the fair market value of FrontStreet's assets and liabilities. Further, certain transaction costs that would normally be capitalized were expensed. Common control between the Partnership and FrontStreet began on June 18, 2007. Accordingly, the statement of operations for periods ending June 30, 2007 has been recast to include the results of FrontStreet from June 18, 2007 through the end of the period.

Conversely, the acquisition of the five percent minority interest is a transaction between independent parties, for which the Partnership applied the purchase method of accounting. The Partnership is in the process of obtaining third-party valuations of fixed and certain intangible assets; thus, the allocation of the purchase price is subject to refinement.

The following table summarizes the book values of the assets acquired and liabilities assumed at the date of common control, following the as-if pooled method of accounting.

		At June 18, 2007 (in thousands)
Current assets	$	8,840
Property, plant and equipment		91,556

Total assets acquired		100,396
Current liabilities		(12,556)
Net book value of assets acquired	$	87,840

The unaudited financial information as of, and for the three and six months ended, June 30, 2008 has been prepared on the same basis as the audited consolidated financial statements included in the Partnership's Annual Report on Form 10-K as amended by Form 8-K filed on May 9, 2008 for the year ended December 31, 2007. 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 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 SEC.

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. Intangible assets, net consist of the following.

	Permits and Licenses	Customer Contracts	Trade Names	Total
		(in thousands)		
Balance at December 31,2007	$ 9,368	$ 68,436	$ -	$ 77,804
Additions	-	102,480	35,100	137,580
Disposals	-	-	-	-
Amortization	(393)	(4,811)	(1,082)	(6,286)
Balance at June 30, 2008	$ 8,975	$ 166,105	$ 34,018	$ 209,098

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The weighted average amortization period for permits and licenses, customer contracts, and trade names are 15, 16, and 15 years, respectively. The expected amortization of the intangible assets for each of the five succeeding years is as follows.

Year ending December 31,		Total (in thousands)
2008 (remaining)	$	6,911
2009		12,358
2010		12,264
2011		10,950
2012		10,713

Recently Issued Accounting Standards. 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. The adoption of SFAS No. 159 in 2008 had no impact on the Partnership's financial position, results of operations or cash flows, as the Partnership has elected to continue valuing its outstanding senior notes at historical cost.

In December 2007, the FASB issued SFAS No. 141(R) "Business Combinations" ("SFAS No. 141(R)"), which significantly changes the accounting for business acquisitions both during the period of the acquisition and in subsequent periods. SFAS No. 141(R) is effective for fiscal years beginning after December 15, 2008. Generally, the effects of SFAS No. 141(R) will depend on future acquisitions.

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

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133" ("SFAS No. 161"). SFAS No. 161 requires enhanced disclosures about derivative and hedging activities. These enhanced disclosures will address (a) how and why a company uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under FASB Statement No. 133 and its related interpretations and (c) how derivative instruments and related hedged items affect a company's financial position, results of operations and cash flows. SFAS No. 161 is effective for fiscal years beginning on or after November 15, 2008, with earlier adoption allowed. The Partnership is currently evaluating the potential impacts on its financial position, results of operations or cash flows of the adoption of this standard.

In March 2008, the FASB issued EITF 07-4, "Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships." EITF 07-4 defines how to allocate net income among the various classes of equity, including incentive distribution rights, narrowing the number of currently acceptable methods. The standard becomes effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Earlier application is not permitted, and must be applied retrospectively for all financial statements presented. Accordingly, in 2009 the Partnership will adopt the new method of calculating earnings per unit. This new standard is not expected to have a material impact on the Partnership's financial position, results of operations or cash flows.

In June 2008, the FASB issued FSP EITF 03-6-1, “Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities.” Based on this guidance, the Partnership will include non-vested units granted under its LTIP in the calculation of basic earnings per unit. The FSP is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those years. All prior-period earnings per unit data will be adjusted. Early application is not permitted. This new standard is not expected to have a material impact on the Partnership’s financial position, results of operations or cash flows.

2. Income (Loss) per Limited Partner Unit

In connection with the CDM acquisition, the Partnership issued 7,276,506 Class D common units. At the commitment date, the sales price of $30.18 per unit represented a $1.10 discount from the fair value of the Partnership’s common units. Under EITF No. 98-5, “Accounting for Convertible Securities with Beneficial Conversion Features or Contingently Adjustable Conversion Ratios,” the discount represented a beneficial conversion feature that is treated as a non-cash distribution for purposes of calculating earnings per unit. The beneficial conversion feature is reflected in income per unit using the effective yield method over the period the Class D common units are outstanding, as indicated on the statements of operations in the line item entitled “beneficial conversion feature for Class D common units.”

The following table provides a reconciliation of the numerator and denominator of the basic and diluted earnings per unit computations for the three and six months ended June 30, 2008.

	For the Three Months Ended June 30, 2008			For the Six Months Ended June 30, 2008		
	Income (Numerator)	Units (Denominator)	Per-Unit Amount	Income (Numerator)	Units (Denominator)	Per-Unit Amount
	(in thousands except unit and per unit data)					
Basic Earnings per Unit						
Limited partner's interest in net income	$ 7,770	62,174,317	$ 0.12	$ 15,826	60,701,912	$ 0.26
Effect of Dilutive Securities						
Common unit options	-	98,665		-	149,186	
Diluted Earnings per Unit	$ 7,770	62,272,982	$ 0.12	$ 15,826	60,851,098	$ 0.26

The following data show securities that could potentially dilute earnings per unit in the future that were not included in the computation of diluted EPS because to do so would have been antidilutive for the periods presented.

	Three Months Ended		Six Months Ended	
	June 30, 2008	June 30, 2007	June 30, 2008	June 30, 2007
Restricted common units	713,925	355,000	713,925	355,000
Common unit options	-	868,568	-	868,568
Class D common units	7,276,506	-	7,276,506	-

3. Acquisitions and Dispositions

CDM Resource Management, Ltd. On January 15, 2008, the Partnership and an indirect wholly owned subsidiary of the Partnership consummated an agreement and plan of merger (the “Merger Agreement”) with CDM Resource Management, Ltd. CDM provides its customers with turn-key natural gas contract compression services to maximize their natural gas and crude oil production, throughput, and cash flow in Texas, Louisiana, and Arkansas. The Partnership operates and manages CDM as a separate reportable segment.

The total purchase price paid by the Partnership for the partnership interests of CDM consisted of (1) the issuance of an aggregate of 7,276,506 Class D common units of the Partnership, which were valued at $219,590,000, (2) the payment of an aggregate of $161,945,000 in cash, and (3) the payment of $316,500,000 to retire CDM’s debt obligations. Of the Class D common units issued, 4,197,303 Class D common units were deposited with an escrow agent pursuant to an escrow agreement. Such common units constitute security to the Partnership for a period of one year after the closing with respect to any obligations under the Merger Agreement, including obligations for breaches of representation, warranties and covenants.

In connection with the CDM merger, the Partnership amended its Agreement of Limited Partnership to create the Partnership’s Class D common units. The Class D common units have the same terms and conditions as the Partnership’s common units, except that the Class D common units are not entitled to participate in distributions of operating surplus by the Partnership. The Class D common units automatically convert into common units on a one-for-one basis on the close of business on the first business day after the record date for the quarterly distribution on the common units for the quarter ending December 31, 2008. The Class D common units were issued in a private offering conducted in accordance with the exemption from the registration requirements of the Securities Act of 1933 under Section 4(2) thereof.

The total purchase price of $699,702,000, including direct transaction costs, was allocated preliminarily as follows.

	At January 15, 2008 (in thousands)
Current assets	$ 19,463
Other assets	4,547
Gas plants and buildings	1,528
Gathering and transmission systems	421,160
Other property, plant and equipment	2,728
Construction-in-progress	36,385
Identifiable intangible assets	80,480
Goodwill	164,522
Assets acquired	730,813

Current liabilities		(31,054)
Other liabilities		(57)
Net assets acquired	$	699,702

The final purchase price allocation, which management expects to be completed before year end, may differ from the above estimates.

Nexus Gas Holdings, LLC. On March 25, 2008, the Partnership acquired Nexus ("Nexus Acquisition") by merger for $88,486,000 in cash, including customary closing adjustments and direct transaction costs. Nexus Gas Partners LLC, the sole member of Nexus prior to the merger ("Nexus Member"), deposited $8,500,000 in an escrow account as security to the Partnership for a period of one year against indemnification obligations and any purchase price adjustment. The Partnership funded the Nexus Acquisition through borrowings under the existing revolving credit facility.

Upon consummation of the Nexus Acquisition, the Partnership acquired Nexus' rights under a Purchase and Sale Agreement (the "Sonat Agreement") between Nexus and Sonat. Pursuant to the Sonat Agreement, Nexus will purchase 136 miles of pipeline from Sonat (the "Sonat Asset Acquisition") that could facilitate the Nexus gathering system's integration into the Partnership's north Louisiana asset base. The Sonat Asset Acquisition is subject to abandonment approval and jurisdictional redetermination by the FERC, as well as customary closing conditions. Upon closing of the Sonat Asset Acquisition, the Partnership will pay Sonat $27,500,000, and, if the closing occurs on or prior to March 1, 2010, on certain terms and conditions as provided in the Merger Agreement, the Partnership will make an additional payment of $25,000,000 to the Nexus Member.

The total purchase price of $88,486,000 was allocated preliminarily as follows.

		At March 25, 2008 (in thousands)
Current assets	$	3,457
Buildings		13
Gathering and transmission systems		16,960
Other property, plant and equipment		4,440
Identifiable intangible assets		57,100
Goodwill		7,187
Assets acquired		89,157
Current liabilities		(671)
Net assets acquired	$	88,486

The final purchase price allocation, which management expects to be completed before year end, may differ from the above estimates.

The following unaudited pro forma financial information has been prepared as if the acquisitions of FrontStreet, CDM and Nexus had occurred as of the beginning of the periods presented. In the six months ended June 30, 2007, the Partnership's acquisition of Pueblo is included since that acquisition occurred in April 2007. Such unaudited pro forma information does not purport to be indicative of the results of operations that would have been achieved if the transactions to which the Partnership is giving pro forma effect actually occurred on the date referred to above or the results of operations that may be expected in the future.

	Pro Forma Results for the							
	Three Months Ended				Six Months Ended			
	June 30, 2008		June 30, 2007		June 30, 2008		June 30, 2007	
	(in thousands except unit and per unit data)							
Revenue	$	546,705	$	333,353	$	959,147	$	630,529
Net income (loss)	$	9,972	$	(4,643)	$	22,134	$	(1,157)
Less:								
General partner's interest in current period net income (loss), including IDR		336		(92)		1,068		(29)
Beneficial conversion feature for Class C common units		-		-		-		1,385
Beneficial conversion feature for Class D common units		1,866		-		3,425		-
Limited partners' interest in net income (loss)	$	7,770	$	(4,551)	$	17,641	$	(2,513)
Basic and Diluted earnings per unit:								
Amount allocated to common and subordinated units	$	7,770	$	(4,865)	$	17,641	$	(2,827)
Weighted average number of common and subordinated units outstanding		62,174,317		47,151,689		60,701,912		44,767,568
Income (loss) per common and subordinated unit	$	0.12	$	(0.10)	$	0.29	$	(0.06)
Distributions per unit	$	0.42	$	0.38	$	0.82	$	0.75
Amount allocated to Class B common units	$	-	$	-	$	-	$	-
		-		-		-		1,314,733

Weighted average number of Class B common units outstanding								
Income per Class B common unit	$	-	$	-	$	-	$	-
Distributions per unit	$	-	$	-	$	-	$	-
Amount allocated to Class C common units	$	-	$	-	$	-	$	1,385
Total number of Class C common units outstanding		-		-		-		2,857,143
Income per Class C common unit due to beneficial conversion feature	$	-	$	-	$	-	$	0.48
Distributions per unit	$	-	$	-	$	-	$	-
Amount allocated to Class D common units	$	1,866	$	-	$	3,425	$	-
Total number of Class D common units outstanding		7,276,506		-		7,276,506		-
Income per Class D common unit due to beneficial conversion feature	$	0.26	$	-	$	0.47	$	-
Distributions per unit	$	-	$	-	$	-	$	-
Amount allocated to Class E common units	$	-	$	314	$	-	$	314
Total number of Class E common units outstanding		4,701,034		4,701,034		4,701,034		4,701,034
Income per Class E common unit	$	-	$	0.07	$	-	$	0.07
Distributions per unit	$	-	$	0.24	$	-	$	0.24

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4. Risk Management Activities

The net fair value of the financial instruments related to the Partnership's risk management activities constituted a net liability of $97,810,000 at June 30, 2008. The Partnership expects to reclassify $51,871,000 of net hedging losses as an offset to revenues or interest expense from accumulated other comprehensive income (loss) in the next twelve months. During the three and six months ended June 30, 2008, the Partnership recorded $18,694,000 and $22,007,000 of mark-to-market losses for certain commodity hedges that do not qualify for hedge accounting. In the three and six months ended June 30, 2008 the Partnership recognized $262,000 and $486,000 of ineffectiveness gains, recovering all prior ineffectiveness losses. The net liabilities from risk management activities have been reduced by $948,000 to reflect the effect of credit risk associated with these instruments.

The Partnership's hedging positions help reduce exposure to variability of future commodity prices through 2010 and future interest rates on $300,000,000 of debt under its revolving credit facility through March 5, 2010.

Effective June 19, 2007, the Partnership elected to account for all outstanding commodity hedging instruments on a mark-to-market basis except for the portion pursuant to which all NGL products for a particular year were hedged and the hedging relationship was, for accounting purposes, effective.

In March 2008, the Partnership entered offsetting trades against its existing 2009 portfolio of mark-to-market hedges, which it believes will substantially reduce the volatility of its existing 2009 hedges. This group of trades, along with the pre-existing 2009 portfolio, will continue to be accounted for on a mark-to-market basis. Simultaneously, the Partnership executed additional 2009 NGL swaps which were designated under SFAS No. 133 as cash flow hedges. In May 2008, the Partnership entered into commodity swaps to hedge its 2010 NGL commodity risk, except for ethane, which are accounted for using mark-to-market accounting.

The Partnership accounts for a portion of its 2008 and all of its 2009 West Texas Intermediate crude oil swaps using mark-to-market accounting. In May 2008, the Partnership entered into West Texas Intermediate crude oil swap to hedge its 2010 condensate price risk, which qualified for hedge accounting in June 2008.

On February 29, 2008, the Partnership entered into two-year interest rate swaps related to $300,000,000 of borrowings under its revolving credit facility, effectively locking the base rate for these borrowings at 2.4 percent, plus the applicable margin (2 percent as of June 30, 2008). These interest rate swaps were designated as cash flow hedges on March 7, 2008.

5. Long-Term Debt

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

		June 30, 2008		December 31, 2007
		(in thousands)		
Senior notes	$	357,500	$	357,500
Revolving loans		805,000		124,000
Total		1,162,500		481,500
Less: current portion		-		-
Long-term debt	$	1,162,500	$	481,500
Availability under revolving credit facility:				
Total credit facility limit	$	900,000	$	500,000

Revolving loans		(805,000)		(124,000)
Letters of credit		(27,257)		(27,263)
Total available	$	67,743	$	348,737

RGS entered into Amendment No. 4 to its Fourth Amended and Restated Credit Facility on January 15, 2008, thereby expanding its revolving credit facility to $750,000,000. RGS also entered into Amendment No. 5 to its Fourth Amended and Restated Credit Facility on February 13, 2008, expanding its revolving credit facility to $900,000,000 and availability for letters of credit to $100,000,000. The Partnership has the option to request an additional $250,000,000 in revolving commitments with ten business days written notice provided that no event of default has occurred or would result due to such increase, and all other additional conditions for the increase of the commitments set forth in the credit facility have been met. These amendments did not materially change other terms of the RGS revolving credit facility.

The outstanding balance of revolving debt under the credit facility bears interest at LIBOR plus a margin or Alternative Base Rate (equivalent to the U.S. prime lending rate) plus a margin, or a combination of both. The weighted average interest rates for the revolving loans and senior notes, including interest rate swap settlements, commitment fees, and amortization of debt issuance costs were 6.49 percent and 8.71 percent for the six months ended June 30, 2008 and 2007, respectively and 6.12 percent and 8.70 percent for the three months ended June 30, 2008 and 2007 respectively. The senior notes bear interest at a fixed rate of 8.375 percent. The estimated fair market value of the senior notes was $368,225,000 as of June 30, 2008.

The senior notes are guaranteed by the Partnership’s subsidiaries (the “Guarantors”) at the date the notes were issued. These note guarantees are the joint and several obligations of the Guarantors. A guarantor may not sell or otherwise dispose of all or substantially all of its properties or assets if such sale would cause a default under the terms of the senior notes. Events of default include nonpayment of principal or interest when due; failure to comply with certain limits on the payment of distributions; failure to make a change of control offer; failure to comply with reporting requirements according to SEC rules and regulations; and defaults on the payment of obligations under other indebtedness of $20,000,000 or more. Since certain subsidiaries do not guarantee the senior notes, the condensed consolidating financial statements of the guarantors and non-guarantors as of and for the six months ended June 30, 2008 are disclosed below.

Condensed Consolidating Balance Sheets
June 30, 2008
Unaudited

	Guarantors	Non Guarantors	Elimination	Consolidated
ASSETS		(in thousands)		
Total current assets	$ 276,169	$ 12,682	$ -	$ 288,851
Property, plant and equipment, net	1,417,382	94,543	-	1,511,925
Total other assets	502,319	-	-	502,319
TOTAL ASSETS	$ 2,195,870	$ 107,225	$ -	$ 2,303,095
LIABILITIES & PARTNERS' CAPITAL				
Total current liabilities	$ 336,492	$ 2,288	$ -	$ 338,780
Long-term liabilities from risk management activities	40,461	-	-	40,461
Other long-term liabilities	15,963	-	-	15,963
Long-term debt	1,162,500	-	-	1,162,500
Minority interest	7,464		-	7,464
Partners' capital	632,990	104,937	-	737,927
TOTAL LIABILITIES & PARTNERS' CAPITAL	$ 2,195,870	$ 107,225	$ -	$ 2,303,095

Condensed Consolidating Statements of Operations
For the Six Months Ended June 30, 2008
Unaudited

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
Total revenues	$ 928,544	$ 23,396	$ -	$ 951,940
Total operating costs and expenses	880,291	19,261	-	899,552
OPERATING INCOME	48,253	4,135	-	52,388
Interest expense, net	(32,188)	-	-	(32,188)
Other income and deductions, net	357	(25)	-	332
Minority interest	(3)	-	-	(3)
INCOME BEFORE INCOME TAXES	16,419	4,110	-	20,529
Income tax expense	209	-	-	209
NET INCOME	$ 16,210	$ 4,110	$ -	$ 20,320

Condensed Consolidating Statements of Cash Flow
For the Six Months Ended June 30, 2008
Unaudited

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
Net cash flows provided by (used in) operating activities	$ 89,683	$ (2,749)	$ -	$ 86,934
Net cash flows provided by (used in) investing activities	(728,053)	(2,400)	-	(725,653)
Net cash flows provided by financing activities	635,733	-	-	635,733

6. Commitments and Contingencies

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

Contingent Purchase of Sonat Assets. In March of 2008, the Partnership, through its Nexus acquisition, obtained the rights to a contingent commitment to purchase 136 miles of pipeline that could facilitate the Nexus gathering system's integration into the Partnership's north Louisiana asset base. The purchase commitment is contingent upon the FERC declaring that the pipeline is no longer subject to its jurisdiction, together with approval of the current owner's abandonment and other customary closing conditions. In the event that all contingencies are satisfactorily resolved, the Partnership will pay Sonat $27,500,000. Furthermore, if the closing occurs on or prior to March 1, 2010, the Partnership will pay an additional $25,000,000 to the sellers, subject to certain terms and conditions.

On April 3, 2008, Sonat filed an application with the FERC seeking authorization to abandon by sale to Nexus 136 miles of pipeline and related facilities. The application also requested a determination that the facilities being sold to Nexus be considered non-jurisdictional, with certain facilities being gathering and certain facilities being intrastate transmission. Four producers submitted letters in support of the application and several Sonat shippers protested the application. The matter is currently pending.

Escrow Payable. At June 30, 2008, $1,504,000 remained in escrow pending the completion by El Paso of environmental remediation projects pursuant to the purchase and sale agreement ("El Paso PSA") related to assets in north Louisiana and the mid-continent area. In the El Paso PSA, El Paso indemnified the predecessor of our operating partnership, RGS, against losses arising from pre-closing and known environmental liabilities subject to a limit of $84,000,000 and subject to certain deductible limits. Upon completion of a Phase II environmental study, the Partnership notified El Paso of remediation obligations amounting to $1,800,000 with respect to known environmental matters and $3,600,000 with respect to pre-closing environmental liabilities.

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

Nexus Escrow. Nexus deposited $8,500,000 in an escrow account as security to the Partnership for a period of one year against indemnification obligations and any purchase price adjustments related to the March 25, 2008 Nexus Acquisition.

Environmental. A Phase I environmental study was performed on certain assets located in west Texas in connection with the pre-acquisition due diligence process in 2004. Most of the identified environmental contamination had either been remediated or was being remediated by the previous owners or operators of the properties. The aggregate potential environmental remediation costs at specific locations were estimated to range from $1,900,000 to $3,100,000. No governmental agency has required the Partnership to undertake these remediation efforts. Management believes that the likelihood that it will be liable for any significant potential remediation liabilities identified in the study is remote. Separately, the Partnership acquired an environmental pollution liability insurance policy in connection with the acquisition to cover any undetected or unknown pollution discovered in the future. The policy covers clean-up costs and damages to third parties, and has a 10-year term (expiring 2014) with a $10,000,000 limit subject to certain deductibles. No claims have been made.

TCEQ Notice of Enforcement. On February 15, 2008, the TCEQ issued a NOE concerning the Partnership's Tilden processing plant located in McMullen County, Texas (the "Plant"). The NOE alleges that, between March 9, 2006, and May 8, 2007, the Plant experienced 15 emission events of various durations from 4 hours to 41 days, which were not reported to TCEQ and other agencies within 24 hours of occurrence. On April 3, 2008, TCEQ presented the Partnership with a written offer to settle the allegation in the NOE in exchange for payment of an administrative penalty of $480,000. The Partnership is continuing to pursue this matter with the TCEQ.

RIGS FERC Petition. On April 29, 2008, the Partnership filed a petition with the FERC seeking approval to maintain RIGS' maximum Section 311 transportation rates. The rate filing was required by a FERC Letter Order issued on September 26, 2005, which approved a settlement in which RIGS agreed to justify its existing rates or establish new rates for Section 311 service by May 1, 2008. The triennial rate review requirement is a standard settlement provision in most intrastate pipeline rate proceedings.

In the petition, RIGS requests to maintain its current maximum rates for both firm and interruptible services as follows:

- firm service: reservation fee of $4.5625 per MMBtu monthly ($0.15 per MMBtu daily) and commodity fee of $0.05 per MMBtu and
- interruptible service: $0.20 per MMBtu.

RIGS also requested a continuation of its existing fuel retention percentage of up to two percent. The proposed rates are subject to refund beginning May 1, 2008.

Keyes Litigation. In August 2008, Keyes Helium Company, LLC ("Keyes") filed suit against Regency Gas Services LP, Regency Energy Partners LP and its general partner. Keyes entered into an output contract with the Partnership's predecessor in 1996 under which it purchased all of the helium produced at the Lakin processing plant in southwest Kansas. In September 2004, the Partnership decided to shut down the Lakin plant and contract with DEFS for the processing of volumes processed at Lakin, as a result of which the Partnership no longer delivered any helium to Keyes. As a result, Keyes alleges it is entitled to an unspecified amount of damages for the costs of covering its purchases of helium. The Partnership is evaluating this claim and plans to defend itself vigorously against the complaint.

7. Related Party Transactions

The employees operating the assets of the Partnership and its subsidiaries and substantially all those providing staff and support services are employees of the General Partner and other affiliates of the Partnership. Pursuant to the Partnership Agreement, our General Partner receives a monthly reimbursement for all direct and indirect expenses that it incurs on behalf of the Partnership. Reimbursements of $8,433,000 and $7,189,000 were recorded in the Partnership's financial statements during the three months ended June 30, 2008 and 2007, respectively, and reimbursements of $15,321,000 and $13,238,000 were recorded in the Partnership's financial statements during the six months ended June 30, 2008 and 2007, respectively, as operating expenses or general and administrative expenses, as appropriate.

In conjunction with distributions by the Partnership to its limited and general partner interests, GE EFS and affiliates received cash distributions of $15,738,000 during the six months ended June 30, 2008 as result of their ownership interests in the Partnership.

In conjunction with distributions by the Partnership to its limited and general partner interests, HM Capital Partners and affiliates received cash distributions of $6,682,000 and $16,152,000 during the six months ended June 30, 2008 and 2007, respectively, as a result of their ownership interests in the Partnership.

In conjunction with distributions by the Partnership to its limited and general partner interests, certain members of management received cash distributions of $877,000 in the six months ended June 30, 2008 as a result of their ownership interests in the Partnership.

In the three months ended June 30, 2008, the Partnership sold a small south Texas asset to a related party for $400,000 and recognized a $331,000 loss.

8. Segment Information

The Partnership has three reportable segments: i) gathering and processing, ii) transportation, and iii) contract compression. Gathering and processing involves collecting raw natural gas from producer wells and transporting it to treating plants where water and other impurities such as hydrogen sulfide and carbon dioxide are removed. Treated gas is then processed to remove the natural gas liquids. The treated and processed natural gas is then transported to market separately from the natural gas liquids. Revenues and the associated cost of sales directly expose the Partnership to commodity price risk, which is managed through derivative contracts and other measures. The Partnership aggregates the results of its gathering and processing activities across five geographic regions into a single reporting segment.

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

The contract compression segment includes designing, sourcing, owning, insuring, installing, operating, servicing, repairing, and maintaining compressors and related equipment, with a focus on meeting the complex requirements of field-wide compression applications, as opposed to targeting the compression needs of individual wells within a field. These field-wide applications include compression for natural gas gathering, natural gas lift for crude oil production and natural gas processing. Revenues in this segment are fee-based, with minimal direct exposure to commodity price risk. The contract compression operations are primarily located in Texas, Louisiana, and Arkansas. The contract compression segment also provides services to certain operations in the gathering and processing segment, creating a portion of 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, for the gathering and processing and for the transportation segments, is defined as total revenues, including service fees, less cost of sales. In the contract compression segment, segment margin is defined as revenues minus direct costs, which primarily consists of compressor repairs. Management believes segment margin is an important measure because it directly relates to volume and commodity price changes. Operation and maintenance expenses are a separate measure used by management to evaluate 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 fluctuate depending on the activities performed during a specific period. The Partnership does not deduct operation and maintenance expenses from total revenues in calculating segment margin because management separately evaluates commodity volume and price changes in segment margin.

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

	Gathering and Processing	Transportation	Contract Compression	Corporate	Eliminations	Total
			(in thousands)			
External Revenue						
For the three months ended June 30, 2008	$ 338,705	$ 175,413	$ 32,587	$ -	$ -	$ 546,705
For the three months ended June 30, 2007	213,961	88,869	-	-	-	302,830
For the six months ended June 30, 2008	600,290	293,796	57,854	-	-	951,940
For the six months ended June 30, 2007	391,078	168,178	-	-	-	559,256
Intersegment Revenue						
For the three months ended June 30, 2008	-	51,982	$ 164	-	(52,146)	-
For the three months ended June 30, 2007	-	33,183	-	-	(33,183)	-
For the six months ended June 30, 2008	-	82,666	282	-	(82,948)	-
For the six months ended June 30, 2007	-	48,001	-	-	(48,001)	-
Cost of Sales						
For the three months ended June 30, 2008	292,216	203,591	2,907	-	(52,027)	446,687
For the three months ended June 30, 2007	174,260	108,683	-	-	(33,183)	249,760
For the six months ended June 30, 2008	499,794	337,965	5,272	-	(82,755)	760,276
For the six months ended June 30, 2007	321,202	188,497	-	-	(48,001)	461,698
Segment Margin						
For the three months ended June 30, 2008	46,489	23,804	29,844	-	(119)	100,018
For the three months ended June 30, 2007	39,701	13,369	-	-	-	53,070
For the six months ended June 30, 2008	100,496	38,497	52,864	-	(193)	191,664
For the six months ended June 30, 2007	69,876	27,682	-	-	-	97,558
Operation and Maintenance						
For the three months ended June 30, 2008	19,408	1,462	11,389	402	(145)	32,516
For the three months ended June 30, 2007	10,483	1,489	-	-	-	11,972
	38,035	2,859	20,234	401	(168)	61,361

For the six months ended June 30, 2008						
For the six months ended June 30, 2007	19,598	3,299	-	-	-	22,897
Depreciation and Amortization						
For the three months ended June 30, 2008	15,246	3,496	7,479	255	-	26,476
For the three months ended June 30, 2007	9,042	3,358	-	303	-	12,703
For the six months ended June 30, 2008	27,916	6,986	12,833	481	-	48,216
For the six months ended June 30, 2007	16,928	6,607	-	595	-	24,130
Assets						
June 30, 2008	1,079,548	363,559	785,489	74,499	-	2,303,095
December 31, 2007	886,477	329,862	-	62,071	-	1,278,410
Goodwill						
June 30, 2008	67,019	34,243	164,522	-	-	265,784
December 31, 2007	59,832	34,243	-	-	-	94,075
Expenditures for Long-Lived Assets						
For the six months ended June 30, 2008	79,219	499	68,230	940	-	148,888
For the six months ended June 30, 2007	60,701	4,800	-	410	-	65,911

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

	Three Months Ended		Six Months Ended	
	June 30, 2008	June 30, 2007	June 30, 2008	June 30, 2007
	(in thousands)			
Net income (loss)	$ 9,972	$ (7,263)	$ 20,320	$ (8,558)
Add (deduct):				
Operation and maintenance	32,516	11,972	61,361	22,897
General and administrative	13,925	19,093	24,809	25,944
Loss on assets sales, net	442	532	468	2,339
Management services termination fee	-	-	3,888	-
Transaction expenses	147	-	534	-
Depreciation and amortization	26,476	12,703	48,216	24,130
Interest expense, net	16,782	15,961	32,188	30,846
Other income and deductions, net	(132)	(170)	(332)	(282)
Minority interest	(69)	17	3	17
Income tax expense (benefit)	(41)	225	209	225
Total segment margin	$ 100,018	$ 53,070	$ 191,664	$ 97,558

9. Equity-Based Compensation

In December 2005, the 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. LTIP awards vest on the basis of one-fourth of the award each year. The Partnership expects to recognize $20,981,000 of compensation expense related to the non-vested grants. All outstanding options are vested and expire ten years after the grant date.

The Partnership makes 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 exercise of the common unit options, the Partnership anticipates settling these obligations with common units. In the three months ended June 30, 2008, two former executives of the Partnership exercised 135,000 unit options.

The common unit options and restricted (non-vested) unit activity for the six months ended June 30, 2008 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	738,668	$ 21.05		
Granted	-	-		
Exercised	(236,800)	20.57		$ 886
Forfeited or expired	(10,700)	21.85		
Outstanding at end of period	491,168	21.26	7.77	1,499
Exercisable at end of period	491,168	21.26		1,499

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

Restricted (Non-Vested) Units	Units	Weighted Average Grant Date Fair Value
Outstanding at beginning of period	397,500	$ 31.62
Granted	427,300	28.56
Vested	(76,375)	31.58
Forfeited or expired	(34,500)	31.58
Outstanding at end of period	713,925	29.80

10. Fair Value Measures

On January 1, 2008, the Partnership adopted the provisions of SFAS No. 157, “Fair Value Measurements” (“SFAS No. 157”), for financial assets and liabilities. SFAS No. 157 became effective for financial assets and liabilities on January 1, 2008. On January 1, 2009, the Partnership will apply the provisions of SFAS No. 157 for non-recurring fair value measurements of non-financial assets and liabilities, such as goodwill, indefinite-lived intangible assets, property, plant and equipment and asset retirement obligations. SFAS No. 157 defines fair value, thereby eliminating inconsistencies in guidance found in various prior accounting pronouncements, and increases disclosures surrounding fair value calculations.

SFAS No. 157 establishes a three-tiered fair value hierarchy that prioritizes inputs to valuation techniques used in fair value calculations. The three levels of inputs are defined as follows:

- Level 1 — unadjusted quoted prices for identical assets or liabilities in active markets accessible by us;
- Level 2 — inputs that are observable in the marketplace other than those inputs classified as Level 1; and
- Level 3 — inputs that are unobservable in the marketplace and significant to the valuation.

SFAS No. 157 encourages entities to maximize the use of observable inputs and minimize the use of unobservable inputs. If a financial instrument uses inputs that fall in different levels of the hierarchy, the instrument will be categorized based upon the lowest level of input that is significant to the fair value calculation.

The Partnership's financial assets and liabilities measured at fair value on a recurring basis are risk management assets and liabilities related to interest rate and commodity swaps. Risk management assets and liabilities are valued using discounted cash flow techniques. These techniques incorporate Level 1 and Level 2 inputs such as future interest rates and commodity prices. These market inputs are utilized in the discounted cash flow calculation considering the instrument's term, notional amount, discount rate and credit risk and are classified as Level 2 in the hierarchy. The Partnership has no financial assets and liabilities as of June 30, 2008 valued based on inputs classified as Level 3 in the hierarchy.

11. Subsequent Events

Partner Distributions. On July 25, 2008, the Partnership declared a distribution of $0.445 per common and subordinated unit including units equivalent to the General Partner’s two percent interest in the Partnership, and an aggregate distribution of $576,000 with respect to incentive distribution rights, payable on August 14, 2008 to unitholders of record at the close of business on August 7, 2008.

Equity Offering. On August 1, 2008, the Partnership issued 9,020,909 common units and received $204,133,000 in proceeds, inclusive of the General Partner’s proportionate capital contribution. The net proceeds were used to repay indebtedness under the Partnership’s revolving credit facility and to fund growth capital projects. The common units were issued under the Partnership’s universal shelf registration. An affiliate of GECC purchased 2,272,727 of these common units.

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

RECENT DEVELOPMENTS.

We completed three acquisitions in the six months ended June 30, 2008.

FrontStreet Hugoton LLC. On January 7, 2008, the Partnership acquired all of the outstanding equity and minority interest (the "FrontStreet Acquisition") of FrontStreet from ASC and EnergyOne. FrontStreet owns a gas gathering system located in Kansas and Oklahoma, which is operated by a third party.

The total purchase price consisted of (a) 4,701,034 Class E common units of the Partnership issued to ASC in exchange for its 95 percent interest and (b) the payment of $11,752,000 in cash to EnergyOne in exchange for its five percent minority interest and the termination of a management services contract valued at $3,888,000. The Partnership financed the cash portion of the purchase price out of its revolving credit facility.

In connection with the FrontStreet Acquisition, the Partnership amended its Agreement of Limited Partnership to create the Partnership's Class E common units. The Class E common units have the same terms and conditions as the Partnership's common units, except that the Class E common units were not entitled to participate in earnings or distributions of operating surplus by the Partnership. The Class E common units were issued in a private offering conducted in accordance with the exemption from the registration requirements of the Securities Act of 1933 as afforded by Section 4(2) thereof. The Class E common units converted into common units on a one-for-one basis on May 5, 2008.

Because the acquisition of ASC's 95 percent interest is a transaction between commonly controlled entities (i.e., the buyer and the seller were each affiliates of GECC), the Partnership accounted for this portion of the acquisition in a manner similar to the pooling of interest method. Under this method of accounting, the Partnership reflected historical balance sheet data for both the Partnership and FrontStreet instead of reflecting the fair market value of FrontStreet's assets and liabilities. Further, certain transaction costs that would normally be capitalized were expensed. Common control between the Partnership and FrontStreet began on June 18, 2007.

CDM Resource Management, Ltd. On January 15, 2008, the Partnership and an indirect wholly owned subsidiary of the Partnership consummated an agreement and plan of merger (the "Merger Agreement") with CDM Resource Management, Ltd. CDM provides its customers with turn-key natural gas contract compression services to maximize their natural gas and crude oil production, throughput, and cash flow in Texas, Louisiana, and Arkansas. The Partnership operates and manages CDM as a separate reportable segment.

The total purchase price paid by the Partnership for the partnership interests of CDM consisted of (1) the issuance of an aggregate of 7,276,506 Class D common units of the Partnership, which were valued at $219,590,000, (2) the payment of an aggregate of $161,945,000 in cash, and (3) the payment of $316,500,000 to retire CDM's debt obligations. Of the Class D common units issued, 4,197,303 Class D common units were deposited with an escrow agent pursuant to an escrow agreement. Such common units constitute security to the Partnership for a period of one year after the closing with respect to any obligations under the Merger Agreement, including obligations for breaches of representation, warranties and covenants.

In connection with the CDM merger, the Partnership amended its Agreement of Limited Partnership to create the Partnership's Class D common units. The Class D common units have the same terms and conditions as the Partnership's common units, except that the Class D common units are not entitled to participate in distributions of operating surplus by the Partnership. The Class D common units automatically convert into common units on a one-for-one basis on the close of business on the first business day after the record date for the quarterly distribution on the common units for the quarter ending December 31, 2008. The Class D common units were issued in a private offering conducted in accordance with the exemption from the registration requirements of the Securities Act of 1933 under Section 4(2) thereof.

Nexus Gas Holdings, LLC. On March 25, 2008, the Partnership acquired Nexus ("Nexus Acquisition") by merger for $88,486,000 in cash, including customary closing adjustments. Nexus Gas Partners LLC, the sole member of Nexus prior to the merger ("Nexus Member"), deposited $8,500,000 in an escrow account as security to the Partnership for a period of one year against indemnification obligations and any purchase price adjustment. The Partnership funded the Nexus Acquisition through borrowings under our existing revolving credit facility.

Upon consummation of the Nexus Acquisition, the Partnership acquired Nexus' rights under a Purchase and Sale Agreement (the "Sonat Agreement") between Nexus and Sonat. Pursuant to the Sonat Agreement, Nexus will purchase 136 miles of pipeline from Sonat (the "Sonat Asset Acquisition") that could facilitate the Nexus gathering system's integration into the Partnership's north Louisiana asset base. The Sonat Asset Acquisition is subject to abandonment approval and jurisdictional redetermination by the FERC, as well as customary closing conditions. Upon closing of the Sonat Asset Acquisition, the Partnership will pay Sonat $27,500,000, and, if the closing occurs on or prior to March 1, 2010, on certain terms and conditions as provided in the Merger Agreement, the Partnership will make an additional payment of $25,000,000 to the Nexus Member.

RIGS FERC Petition. On April 29, 2008, we filed a petition with the FERC seeking approval to maintain RIGS' maximum Section 311 transportation rates. The rate filing was required by a FERC Letter Order issued on September 26, 2005, which approved a settlement in which RIGS agreed to justify its existing rates or establish new rates for Section 311 service by May 1, 2008. The triennial rate review requirement is a standard settlement provision in most intrastate pipeline rate proceedings.

In the petition, RIGS requests to maintain its current maximum rates for both firm and interruptible services as follows:

- firm service: reservation fee of $4.5625 per MMBtu monthly ($0.15 per MMBtu daily) and commodity fee of $0.05 per MMBtu and
- interruptible service: $0.20 per MMBtu.

RIGS also requested a continuation of its existing fuel retention percentage of up to two percent. The proposed rates are subject to refund beginning May 1, 2008.

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TCEQ Notice of Enforcement. On February 15, 2008, the TCEQ issued a NOE concerning the Partnership's Tilden processing plant located in McMullen County, Texas (the "Plant"). The NOE alleges that, between March 9, 2006, and May 8, 2007, the Plant experienced 15 emission events of various durations from 4 hours to 41 days, which were not reported to TCEQ and other agencies within 24 hours of occurrence. On April 3, 2008, TCEQ presented us with a written offer to settle the allegation in the NOE in exchange for payment of an administrative penalty of $480,000. We are continuing to pursue this matter with the TCEQ.

Equity Offering. On August 1, 2008, the Partnership issued 9,020,909 common units and received $204,133,000 in proceeds, inclusive of the General Partner's proportionate capital contribution. The net proceeds were used to repay indebtedness under the Partnership's revolving credit facility and to fund growth capital projects. The common units were issued under the Partnership's universal shelf registration. An affiliate of GECC purchased 2,272,727 of these common units.

TRENDS IN INDUSTRY. Recently, a number of key producers have announced the discovery of potentially significant gas reserves in the Haynesville Shale located in north Louisiana that encompasses more than 3,000 square miles. We believe our Louisiana assets, including our recently acquired Nexus system, are well positioned to capitalize on this new development.

OUR OPERATIONS. We manage our business and analyze and report our results of operations through three business segments.

- Gathering and Processing: We provide "wellhead-to-market" services to producers of natural gas, which include transporting raw natural gas from the wellhead through gathering systems, processing raw natural gas to separate NGLs from the raw natural gas and selling or delivering the pipeline-quality natural gas and NGLs to various markets and pipeline systems;
- Transportation: We deliver natural gas from northwest Louisiana to more favorable markets in northeast Louisiana through our 320-mile Regency Intrastate Pipeline system; and
- Contract Compression: We provide customers with turn-key natural gas compression services to maximize their natural gas and crude oil production, throughput, and cash flow. Our integrated solutions include a comprehensive assessment of a customer's natural gas contract compression needs and the design and installation of a compression system that addresses those particular needs. We are responsible for the installation and ongoing operation, service, and repair of our compression units, which we modify as necessary to adapt to our customers' changing operating conditions.

HOW WE EVALUATE OUR OPERATIONS. Our management uses a variety of financial and operational measurements to analyze our performance. We view these key performance indicators as important tools for evaluating the success of our operations and review these key performance indicators on a monthly basis for consistency and trends. For our gathering and processing and transportation segments, the key performance indicators include volumes, segment margin, and operating and maintenance expenses. For our contract compression segment, the key performance indicators include revenue generating horsepower, average horsepower per revenue generating compression unit, segment margin, and operation and maintenance expenses. Management also reviews EBITDA for each reportable segment and in total to analyze performance.

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 activities 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.

Revenue Generating Horsepower. Revenue generating horsepower growth is the primary driver for revenue growth in the contract compression segment, and it is also the base measure for evaluating our operational efficiency. Revenue generating horsepower is our total available horsepower less horsepower under contract that is not generating revenue, and idle horsepower.

Average Horsepower per Revenue Generating Compression Unit. We calculate average horsepower per revenue generating compression unit as our revenue generating horsepower divided by the number of revenue generating compression units.

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 transportation 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.

We calculate our contract compression segment margin as our revenues generated from our contract compression operations minus the direct costs, primarily compressor unit repairs, associated with those revenues.

Total Segment Margin. Segment margin from gathering and processing, transportation, contract compression and inter-segment eliminations comprise total segment margin. We use total segment margin as a measure of performance. The reconciliation of the non-GAAP financial measure, total segment margin, to its most directly comparable GAAP measure, net income (loss), is included in Note 8, Segment Information, within the condensed consolidated financial statements included in Item 1 of this report.

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 flowing 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 measures, net loss and net cash flows provided by operating activities.

	Six Months Ended			
	June 30, 2008		June 30, 2007	
	(in thousands)			
Net cash flows provided by operating activities	$	86,934	$	32,596
Add (deduct):				
Depreciation and amortization		(49,598)		(24,823)
Equity income and minority interest in earnings		-		26
Risk management portfolio valuation changes		(20,582)		591
Loss on assets sales		(468)		(2,340)
Unit based compensation expenses		(1,839)		(14,085)
Changes in current assets and liabilities:				
Trade accounts receivables and accrued revenues		72,784		17,653
Other current assets		2,914		(365)
Trade accounts payable, accrued cost of gas and liquids, and accrued liabilities		(53,088)		(18,350)
Other current liabilities		(15,314)		41
Other assets and liablities		(1,423)		498
Net income	$	20,320	$	(8,558)
Add:				
Interest expense, net		32,188		30,846
Depreciation and amortization		48,216		24,130
Income tax expense		209		225
EBITDA	$	100,933	$	46,643

CASH DISTRIBUTIONS. On July 25, 2008, the Partnership declared a distribution of $0.445 per common and subordinated unit including units equivalent to the General Partner’s two percent interest in the Partnership, and an aggregate distribution of $576,000 with respect to incentive distribution rights, payable on August 14, 2008 to unitholders of record at the close of business on August 7, 2008.

RESULTS OF OPERATIONS

Three Months Ended June 30, 2008 vs. Three Months Ended June 30, 2007

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

	Three Months Ended June 30, 2008	June 30, 2007	Change	Percent
	(in thousands except percentages and volume data)			
Revenues	$ 546,705	$ 302,830	$ 243,875	81%
Cost of sales	446,687	249,760	196,927	79
Total segment margin (1)	100,018	53,070	46,948	88
Operation and maintenance	32,516	11,972	20,544	172
General and administrative	13,925	19,093	(5,168)	27
Loss on asset sales, net	442	532	(90)	17
Transaction expenses	147	-	147	N/M
Depreciation and amortization	26,476	12,703	13,773	108
Operating income	26,512	8,770	17,742	202
Interest expense, net	(16,782)	(15,961)	(821)	5
Other income and deductions, net	132	170	(38)	22
Minority interest	69	(17)	86	506
Income tax expense (benefit)	(41)	225	(266)	118
Net income (loss)	$ 9,972	$ (7,263)	$ 17,235	237%
System inlet volumes (MMbtu/d) (2)	1,519,790	1,232,343	287,446	23
Revenue generating horsepower (3)	669,804	-	-	N/A

(1) For a reconciliation of total segment margin to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read “Item 1. Financial Statements – Note 8, Segment Information.”
(2) System inlet volumes include total volumes taken into both our gathering and processing and transportation systems.
(3) Revenue generating horsepower is the primary operating measure for our contract compression segment.
N/M – not meaningful.
N/A – not applicable as we acquired the business in January 2008.

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

	Three Months Ended June 30, 2008	June 30, 2007	Change	Percent
	(in thousands except percentage and volume data)			
Segment Financial and Operating Data:				
Gathering and Processing Segment				
Financial data:				
Segment margin (1)	$ 46,489	$ 39,701	$ 6,788	17%
Operation and maintenance	19,408	10,483	8,925	85

Operating data:				
Throughput (MMbtu/d) (2)	995,922	769,613	226,309	29
NGL gross production (Bbls/d)	22,526	20,967	1,559	7
Transportation Segment				
Financial data:				
Segment margin (1)	$ 23,804	$ 13,369	$ 10,435	78
Operation and maintenance	1,462	1,489	(27)	2
Operating data:				
Throughput (MMbtu/d) (2)	793,339	777,927	15,412	2
Contract Compression Segment				
Financial data:				
Segment margin (1)	$ 29,844	$ -	$ 29,844	N/A
Operation and maintenance	11,389	-	$ 11,389	N/A

(1) In 2008, combined segment margin varies from consolidated total segment margin due to inter-segment eliminations between the contract compression, transportation, and gathering and processing segments.
(2) Combined throughput volumes for the gathering and processing and transportation segments vary from consolidated system inlet volumes due to inter-segment eliminations between the two segments.
N/A – not applicable as we acquired the business in January 2008.

The tables below contain key performance indicators for the contract compression segment.

	For the Period Ended	
	March 31, 2008	June 30, 2008
Revenue generating horsepower	615,852	669,804
Revenue generating units	725	789
Average horsepower	849	849

For the Period Ended June 30, 2008			
Horsepower Range	Revenue Generating Horsepower	Percentage of Revenue Generating Horsepower	Number of Units
0-499	50,878	8%	306
500-999	73,936	11%	119
1,000+	544,990	81%	364
	669,804	100%	789

Net Income. Net income for the three months ended June 30, 2008 was $9,972,000 compared to net loss of $7,263,000 for the three months ended June 30, 2007, a $17,235,000 increase. An increase in total segment margin of $46,948,000 and the absence in the three months ended June 30, 2008 of an $11,928,000 charge in the comparable period of 2007 related to the Partnership's long-term incentive plan were partially offset by:

- an increase in operation and maintenance expense of $20,544,000 primarily due to operation and maintenance expenses related to our CDM and FrontStreet acquisitions and increased contractor and employee-related expenses in the gathering and processing segment;
- an increase in depreciation and amortization expense of $13,773,000 primarily due to our CDM, FrontStreet and Nexus acquisitions and organic growth projects; and
- an increase in general and administrative expenses of $6,760,000 primarily due to our CDM acquisition and increased employee-related expenses, excluding the $11,928,000 charge to the Partnership's long-term incentive plan in the three months ended June 30, 2007.

Segment Margin. Total segment margin for the three months ended June 30, 2008 increased $46,948,000 compared with the three months ended June 30, 2007. This increase was attributable to an increase of $6,788,000 in gathering and processing segment margin, an increase of $10,435,000 in transportation segment margin and the addition of $29,844,000 in contract compression segment margin in the three months ended June 30, 2008, as further discussed below. In 2008, combined segment margin varies from total segment margin due to $119,000 in inter-segment eliminations between our reportable segments.

Gathering and processing segment margin increased to $46,489,000 for the three months ended June 30, 2008 from $39,701,000 for the three months ended June 30, 2007. The major components of this increase were as follows:

- $9,917,000 from the operations of our FrontStreet assets;
- $7,407,000 from organic growth projects in south Texas;
- $2,630,000 from the operations of our Nexus assets;
- $2,419,000 from increased sulfur prices;
- $2,124,000 from increased throughput volumes in north Louisiana;
- $(17,183,000) from non-cash changes in the value of certain risk management contracts; and
- $(526,000) from various other sources.

Transportation segment margin increased to $23,804,000 for the three months ended June 30, 2008 from $13,369,000 for the three months ended June 30, 2007. The major components of this increase were as follows:

- $8,143,000 from increased operational efficiencies coupled with increased commodity prices;
- $1,553,000 from increased throughput volumes;
- $1,396,000 in increased margins associated with our limited marketing function; and
- $(657,000) from non-cash changes in the value of certain risk management contracts.

Contract compression segment margin was $29,844,000 in the three months ended June 30, 2008 which consisted of $32,751,000 of operating revenues and $2,907,000 of direct operating costs.

Operation and Maintenance. Operations and maintenance expense increased to $32,516,000 in the three months ended June 30, 2008 from $11,972,000 for the corresponding period in 2007, a 172 percent increase. This increase is primarily the result of the following factors:

- $11,389,000 related to our contract compression business acquired in January 2008;
- $5,180,000 related to our FrontStreet assets, primarily contractor expense from the three months ended June 30, 2008 versus twelve days in 2007;
- $2,019,000 increase in employee-related expenses primarily in the gathering and processing segment due to hiring new employees, salary increases and an increase in the bonus accrual resulting from operational and financial results exceeding our budgeted results;
- $828,000 increase in contractor expense in the gathering and processing segment related primarily to assets acquired in 2007, which are operated by a third party;
- $553,000 increase in utility expenses primarily in the gathering and processing segment due to higher prices; and
- $309,000 increase in rental expense primarily related to our Nexus acquisition in March 2008 in the gathering and processing segment.

General and Administrative. General and administrative expense decreased to $13,925,000 in the three months ended June 30, 2008 from $19,093,000 for the same period in 2007, a 27 percent decrease. In June 2007, the Partnership incurred a one-time charge of $11,928,000 related to its long-term incentive plan associated with the change in control of the General Partner. Absent this charge, general and administrative expense increased by $6,760,000. This increase is primarily due to:

- $4,163,000 related to our contract compression assets acquired January 2008;
- $2,344,000 increase in employee-related expenses primarily due to an increase in the bonus accrual resulting from operational and financial results exceeding our budgeted results; and
- $264,000 increase in professional and consulting service fees related to recruitment services, and performance under consulting service agreements with two former executives.

Depreciation and Amortization. Depreciation and amortization expense increased to $26,476,000 in the three months ended June 30, 2008 from $12,703,000 for the three months ended June 30, 2007, a 108 percent increase. The following factors contributed to this increase:

- $7,479,000 related to our contract compression business acquired in January 2008;
- $3,301,000 related to our FrontStreet assets;
- $1,994,000 related to various organic growth projects completed since June 2007 primarily in the gathering and processing segment; and
- $999,000 related to our Nexus acquisition in March 2008.

Interest Expense, Net. Interest expense, net increased $821,000, or 5 percent, in the three months ended June 30, 2008 compared to the same period in 2007. Of this increase, $5,786,000 was attributable to increased levels of borrowings, offset by a decrease of $4,966,000 primarily attributable to lower interest rates.

Six Months Ended June 30, 2008 vs. Six Months Ended June 30, 2007

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

	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007	Change	Percent
	(in thousands except percentages and volume data)			
Revenues	$ 951,940	$ 559,256	$ 392,684	70%
Cost of sales	760,276	461,698	298,578	65
Total segment margin (1)	191,664	97,558	94,106	96
Operation and maintenance	61,361	22,897	38,464	168
General and administrative	24,809	25,944	(1,135)	4
Loss on asset sales, net	468	2,339	(1,871)	80
Management service termination fee	3,888	-	3,888	N/M
Transaction expenses	534	-	534	N/M
Depreciation and amortization	48,216	24,130	24,086	100
Operating income	52,388	22,248	30,140	135
Interest expense, net	(32,188)	(30,846)	(1,342)	4
Other income and deductions, net	332	282	50	18
Minority interest	(3)	(17)	14	82
Income tax expense	209	225	(16)	7
Net income (loss)	$ 20,320	$ (8,558)	$ 28,878	337%
System inlet volumes (MMbtu/d) (2)	1,448,173	1,183,366	264,807	22

Revenue generating horsepower (3)	669,804	-	-	N/A

(1) For a reconciliation of total segment margin to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read "Item 1. Financial Statements – Note 8, Segment Information."
(2) System inlet volumes include total volumes taken into both our gathering and processing and transportation systems.
(3) Revenue generating horsepower is the primary operating measure for our contract compression segment.
N/M – not meaningful.
N/A – not applicable as we acquired the business in January 2008.

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

	Six Months Ended June 30, 2008	June 30, 2007	Change	Percent
	(in thousands except percentages and volume data)			
Segment Financial and Operating Data:				
Gathering and Processing Segment				
Financial data:				
Segment margin (1)	$ 100,496	$ 69,876	$ 30,620	44%
Operation and maintenance	38,035	19,598	18,437	94
Operating data:				
Throughput (MMbtu/d) (2)	956,248	749,527	206,721	28
NGL gross production (Bbls/d)	22,796	20,510	2,286	11
Transportation Segment				
Financial data:				
Segment margin (1)	$ 38,497	$ 27,682	$ 10,815	39
Operation and maintenance	2,859	3,299	(440)	13
Operating data:				
Throughput (MMbtu/d) (2)	762,673	741,395	21,278	3
Contract Compression Segment				
Financial data:				
Segment margin (1)	$ 52,864	$ -	$ 52,864	N/A
Operation and maintenance	20,234	-	$ 20,234	N/A

(1) In 2008, combined segment margin varies from consolidated total segment margin due to inter-segment eliminations between the contract compression, transportation, and gathering and processing segments.
(2) Combined throughput volumes for the gathering and processing and transportation segment vary from consolidated system inlet volumes due to inter-segment eliminations between the two segments.
N/A – not applicable as we acquired the business in January 2008.

Net Income. Net income for the six months ended June 30, 2008 was $20,320,000 compared to net loss of $8,558,000 for the six months ended June 30, 2007, a $28,878,000 increase. An increase in total segment margin of $94,106,000 and the absence in the six months ended June 30, 2008 of an $11,928,000 charge in the comparable period of 2007 related to the Partnership’s long-term incentive plan were partially offset by:

- an increase in operation and maintenance expense of $38,464,000 primarily due to operation and maintenance expenses related to our CDM and FrontStreet acquisitions and increased contractor and employee-related expenses in the gathering and processing segment;
- an increase in depreciation and amortization expense of $24,086,000 due to our CDM, FrontStreet, Nexus and Pueblo acquisitions and organic growth projects;
- an increase in general and administrative expenses of $10,793,000 primarily due to our CDM acquisition and increased employee-related expenses, excluding the $11,928,000 charge to the Partnership’s long-term incentive plan in the three months ended June 30, 2007; and
- a payment in the six months ended June 30, 2008 of a management contract services termination fee of $3,888,000 related to the acquisition of FrontStreet.

Segment Margin. Total segment margin for the six months ended June 30, 2008 increased $94,106,000 compared with the six months ended June 30, 2007. This increase was attributable to an increase of $30,620,000 in gathering and processing segment margin, an increase of $10,815,000 in transportation segment margin and the addition of $52,864,000 in contract compression segment margin in the six months ended June 30, 2008, as discussed below. In 2008, combined segment margin varies from total segment margin due to $193,000 in inter-segment eliminations between the contract compression, gathering and processing, and transportation segments.

Gathering and processing segment margin increased to $100,496,000 for the six months ended June 30, 2008 from $69,876,000 for the six months ended June 30, 2007. The major components of this increase were as follows:

- $22,104,000 from the operations of our FrontStreet assets;
- $13,907,000 from organic growth projects in south Texas;
- $4,397,000 from various other sources in the segment;
- $3,644,000 from increased throughput volumes in north Louisiana;
- $3,385,000 from increased sulfur prices;
- $2,791,000 from the operation of the Nexus assets acquired in March 2008; and
- $(19,608,000) from non-cash changes in the value of certain risk management contracts.

Transportation segment margin increased to $38,497,000 for the six months ended June 30, 2008 from $27,682,000 for the six months ended June 30, 2007. The major components of this increase were as follows:

- $7,134,000 from increased operational efficiencies coupled with increased commodity prices;
- $2,665,000 from increased throughput volumes;
- $1,673,000 in increased margins associated with our limited marketing function; and
- $(657,000) from non-cash changes in the value of certain risk management contracts.

Contract compression segment margin was $52,864,000 in the six months ended June 30, 2008 which consisted of $58,136,000 of operating revenue and $5,272,000 of direct operating costs.

Operation and Maintenance. Operation and maintenance expense increased to $61,361,000 in the six months ended June 30, 2008 from $22,897,000 for the corresponding period in 2007, a 168 percent increase. This increase is primarily the result of the following factors:

- $20,234,000 related to our contract compression business acquired in January 2008;
- $12,026,000 related to our FrontStreet assets, primarily contractor expense from the six months ended June 30, 2008 versus 12 days in 2007;
- $2,594,000 increase in employee expenses in the gathering and processing segment due to hiring new employees, salary increases and an increase in the bonus accrual resulting from operational and financial results exceeding our budgeted results;
- $1,686,000 increase in contractor expense in the gathering and processing segment related primarily to assets acquired in 2007, which are operated by a third party;
- $1,844,000 increase in various operation and maintenance expenses primarily in the gathering and processing segment;
- $707,000 increase in utility expenses in the gathering and processing segment due to higher prices; and was partially offset by
- $627,000 loss related to an unplanned outage expense in the six months ended June 30, 2007.

General and Administrative. General and administrative expense decreased to $24,809,000 in the six months ended June 30, 2008 from $25,944,000 for the same period in 2007, a 4 percent decrease. In June 2007, the Partnership incurred a one-time charge of $11,928,000 related to the change in control of the General Partner. Absent this charge, general and administrative expense increased by $10,793,000, primarily due to:

- $7,603,000 related to our contract compression business acquired in January 2008;
- $2,494,000 increase in employee related expenses due to hiring new employees, salary increases and an increase in the bonus accrual resulting from operational and financial results exceeding our budgeted results; and
- $696,000 increase in various other general and administrative expenses.

Management Services Termination Fee. In the six months ended June 30, 2008, we recorded a charge of $3,888,000 for the termination of a long-term management services contract associated with our FrontStreet acquisition.

Depreciation and Amortization. Depreciation and amortization expense increased to $48,216,000 in the six months ended June 30, 2008 from $24,130,000 for the six months ended June 30, 2007, a 100 percent increase. The increase in depreciation and amortization expense is due to the following factors:

- $12,833,000 related to our contract compression assets acquired January 2008;
- $5,686,000 related to our FrontStreet assets;
- $3,981,000 related to various organic projects completed since the June 2007, primarily in the gathering and processing segment;
- $999,000 related to our Nexus acquisition in March 2008; and
- $587,000 related to our Pueblo acquisition in April 2007.

Interest Expense, Net. Interest expense, net increased $1,342,000, or 4 percent, in the six months ended June 30, 2008 compared to the same period in 2007. Of this increase, $9,764,000 was attributable to increased levels of borrowings, offset by a decrease of $8,422,000 primarily attributable to lower interest rates.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES. In addition to the information set forth in this report, further 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, 2007.

As-if Pooling of Interest Method of Accounting. We account for acquisitions where common control exists by following the as-if pooling method of accounting as described in SFAS No. 141, “Business Combinations.” Under this method of accounting, we reflect the historical balance sheet data for both the acquirer and acquiree instead of reflecting the fair market value of acquiree's assets and liabilities. In common control acquisitions where a minority interest is also acquired, we use the purchase method of accounting for the minority interest. Further, certain transaction costs that would normally be capitalized are expensed.

Fair Value Measurements. On January 1, 2008, we adopted the provisions of SFAS No. 157 for financial assets and liabilities. SFAS No. 157 defines fair value, thereby eliminating inconsistencies in guidance found in various prior accounting pronouncements, and increases disclosures surrounding fair value calculations. The adoption of SFAS No. 157 for financial assets and liabilities did not have a material impact on our financial position or cash flows for the three months ended March 31, 2008.

SFAS No. 157 establishes a three-tiered fair value hierarchy that prioritizes inputs to valuation techniques used in fair value calculations. The three levels of inputs are defined as follows:

- Level 1 — unadjusted quoted prices for identical assets or liabilities in active markets accessible by us;
- Level 2 — inputs that are observable in the marketplace other than those inputs classified as Level 1; and
- Level 3 — inputs that are unobservable in the marketplace and significant to the valuation.

SFAS No. 157 encourages us to maximize the use of observable inputs and minimize the use of unobservable inputs. If a financial instrument valuation uses inputs that fall in different levels of the hierarchy, the instrument will be categorized based upon the lowest level of input that is significant to the fair value calculation. Our financial assets and liabilities measured at fair value on a recurring basis are derivative financial instruments consisting of interest rate swaps and commodity swaps.

OTHER MATTERS.

Information regarding the Partnership's commitments and contingencies are included in Note 6-Commitments and Contingencies to the condensed consolidated financial statements included in Item 1 of this report.

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, including $67,743,000 available under our revolving credit facility, will be sufficient to meet our minimum quarterly cash distributions and our requirements for working capital and growth capital expenditures for the next twelve months.

Working Capital Surplus (Deficit). Working capital is the amount by which current assets exceed current liabilities and is a measure of our ability to pay our liabilities as they become due. When we incur growth capital expenditures, we experience working capital deficits as we fund construction expenditures out of working capital until they are permanently financed. Our working capital is also influenced by current risk management assets and liabilities due to fair market value changes in our derivative positions being reflected on our balance sheet. These represent our expectations for the settlement of risk management rights and obligations over the next 12 months, and so must be viewed differently from trade accounts receivable and accounts payable which settle over a much shorter span of time. When our derivative positions are settled, we expect an offsetting physical transaction, and, as a result, we do not expect risk management assets and liabilities to affect our ability to pay bills as they come due. Our contract compression segment records significant deferred revenues, a current liability. The deferred revenues represent billings in advance of services performed. As the revenues associated with the deferred revenues are earned, the liability is reduced.

Our working capital deficit increased by $31,564,000 from December 31, 2007 to June 30, 2008, primarily due to:

- an increase in net risk management liabilities of $28,859,000;
- an increase in other current liabilities of $15,314,000 primarily resulting from deferred revenues from our contract compression segment, increased accrued interest associated with higher borrowing levels on our revolving credit facility, increased property tax accruals and increased pipeline imbalance accruals primarily in the transportation segment; and
- partially offsetting these decreases in working capital was an increase in net accounts receivable and payable of $12,681,000 primarily driven by increased total segment margin and the timing of cash receipts and payments.

Cash Flows from Operations. Net cash flows provided by operating activities increased $54,338,000 for the six months ended June 30, 2008 as compared to the six months ended June 30, 2007. Our cash flows from operations increased primarily due to increased segment margin from our FrontStreet and CDM acquisitions in January 2008, our Nexus acquisition in late March 2008, our Pueblo acquisition in April 2007 and organic growth in our gathering and processing segment.

Cash Flows from Investing Activities. Net cash flows used in investing activities increased $629,910,000 in the six months ended June 30, 2008 compared to the six months ended June 30, 2007. Our increase in cash flows from investing activities was primarily attributable to our FrontStreet and CDM acquisitions in January 2008, our Nexus acquisition in March 2008 and higher growth and maintenance capital expenditures discussed in “Capital Requirements.”

Cash Flows from Financing Activities. Net cash flows provided by financing activities increased $549,568,000 in the six months ended June 30, 2008 compared to the six months ended June 30, 2007 primarily due to increased borrowings under our revolving credit facility used to fund our FrontStreet, CDM and Nexus acquisitions.

Equity Offering. On August 1, 2008, the Partnership issued 9,020,909 common units and received $204,133,000 in proceeds, inclusive of the General Partner's proportionate capital contribution. The net proceeds were used to repay indebtedness under the Partnership's revolving credit facility and to fund growth capital projects. The common units were issued under the Partnership's universal shelf registration. An affiliate of GECC purchased 2,272,727 of these common units.

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, 2008, we incurred $132,406,000 of growth capital expenditures. Growth capital expenditures primarily relate to growth capital projects listed below:

- $62,900,000 for the fabrication of new compression packages and ancillary assets for our contract compression segment;
- $17,732,000 for constructing 20 miles of 10 inch diameter pipeline, which connects the Fashing Processing Plant to our Tilden Processing Plant in south Texas and for reconfiguring our Tilden Processing Plant. These projects were substantially complete in the three months ended June 30, 2008;
- $9,492,000 for construction of pipeline, compression and treating facilities related to a joint venture in south Texas;
- $6,238,000 for constructing 40 miles of 10 inch diameter pipeline and compression facilities in west Texas to be completed in the second half of 2008;
- $6,113,000 for the installation of gathering and compression facilities in south Texas; and
- $5,626,000 for additional processing, compression and gathering facilities in north Louisiana.

Our 2008 growth capital expenditure budget includes $365,000,000 of currently identified organic growth capital expenditures, including $132,000,000 for an additional 194,800 horsepower of compression for our contract compression segment. Other major projects included in our 2008 growth capital expenditure budget are:

- $122,000,000 for expansion of our transportation system;
- $14,000,000 for construction of pipeline, compression and treating facilities related to a joint venture in south Texas;
- $18,500,000 for constructing 40 miles of 10 inch diameter pipeline and compression facilities in west Texas to be completed in the second half of 2008; and
- $18,000,000 for constructing 20 miles of 10 inch diameter pipeline, which connects the Fashing Processing Plant to our Tilden Processing Plant in south Texas and for reconfiguring our Tilden Processing Plant. These projects were substantially complete in the three months ended June 30, 2008.

Maintenance Capital Expenditures. In the six months ended June 30, 2008, we incurred $8,488,000 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 six months ended June 30, 2008, we borrowed $681,000,000 under our revolving credit facility primarily to finance our growth capital expenditures and first quarter 2008 acquisitions. The following table summarizes our total contractual cash obligations for long-term debt and purchase obligations as of June 30, 2008. This table excludes capital and operating lease obligations as these amounts have not materially changed since December 31, 2007.

			Payment Period		
Contractual Cash Obligations	Total	2008	2009-2010	2011-2012	Thereafter
			(in thousands)		
Long-term debt (including interest) (1)	$ 1,427,746	$ 31,062	$ 124,248	$ 884,995	$ 387,441
Purchase obligations	138,006	118,099	19,907	-	-
Total (2) (3)	$ 1,565,752	$ 149,161	$ 144,155	$ 884,995	$ 387,441

(1) Assumes a constant LIBOR interest rate of 2.46 percent plus the applicable margin (2.0 percent as of June 30, 2008) for our revolving credit facility. The principal of our outstanding senior notes ($357,500,000) bears a fixed interest rate of 8 3/8 percent.
(2) Excludes physical and financial purchases of natural gas, NGLs, and other commodities due to the nature of both the price and volume components of such purchases, which vary on a daily or monthly basis. Additionally, we do not have contractual commitments for fixed price and/or fixed quantities of any material amount.
(3) Excludes deferred tax liabilities of $8,397,000 as the amount payable by period can not be reliably estimated in light of future business plans for the entity that generates the deferred tax liability.

Item 3. Quantitative and Qualitative Disclosures About Market Risk
Commodity Price Risk. We are a net seller of NGLs, condensate, sulfur and natural gas. As such, our financial results are exposed to fluctuations in commodity pricing. We have executed swap contracts settled against crude oil, ethane, propane, normal butane, iso butane, and natural gasoline. We have hedged our expected exposure to declines in prices for NGLs and condensate volumes produced for our account in the approximate percentages set forth below:

	2008	2009	2010
NGLs	94%	86%	30%
Condensate	67%	67%	67%

We continually monitor our hedging and contract portfolio and expect to continue to adjust our hedge position as conditions warrant.

In March 2008, the Partnership entered offsetting trades against its existing 2009 portfolio of mark-to-market hedges, which it believes will substantially reduce the volatility of its existing 2009 hedges. This group of trades, along with the pre-existing 2009 portfolio, will continue to be accounted for on a mark-to-market basis. Simultaneously, the Partnership executed additional 2009 NGL swaps which were designated under SFAS No. 133 as cash flow hedges. In May 2008, the Partnership entered into commodity swaps to hedge its 2010 NGL commodity risk, except for ethane, which are accounted for using mark-to-market accounting.

The Partnership accounts for a portion of its 2008 and all of its 2009 West Texas Intermediate crude oil swaps using mark-to-market accounting. In May 2008, the Partnership entered into a West Texas Intermediate crude oil swap to hedge its 2010 condensate risk, which qualified for hedge accounting in June 2008.

On February 29, 2008, the Partnership entered into two-year interest rate swaps related to $300,000,000 of borrowings under its revolving credit facility, effectively locking the base rate for these borrowings at 2.4 percent, plus the applicable margin (2 percent as of June 30, 2008). These interest rate swaps were designated as cash flow hedges on March 7, 2008.

The following table sets forth certain information regarding our NGL and interest rate swaps outstanding at June 30, 2008. The relevant index price for commodities 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	Underlying	Notional Volume/Amount		We Pay	We Receive			Fair Value Asset/(Liablity) (in thousands)
July 2008-December 2009	Ethane	1,075	(MBbls)	Index	$	0.58-$0.80	($/gallon)	$ (13,513)
July 2008-December 2010	Propane	939	(MBbls)	Index	$	0.93-$1.5325	($/gallon)	(23,099)
January 2009-December 2010	Iso Butane	404	(MBbls)	Index	$	1.685-$1.915	($/gallon)	(2,689)
July 2008-December 2010	Normal Butane	212	(MBbls)	Index	$	1.12-1.895	($/gallon)	(16,197)
July 2008-December 2010	Natural Gasoline	393	(MBbls)	Index	$	1.41-$2.53	($/gallon)	(18,348)
July 2008-December 2010	West Texas Intermediate Crude	594	(MBbls)	Index	$	68.17-$121.30	($/Bbl)	(28,989)
July 2008-March 2010	Interest Rate	$ 300,000,000		2.40%		One-month	LIBOR	4,077
Credit risk adjustment								948
							Total Fair Value	$ (97,810)

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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 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, 2008 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. There have been no 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.

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 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, 2007 which materially affect our business, financial condition or future results. The risks described in this report and in our Annual Report on Form 10-K are not the only risks facing our Partnership.

Our operations may incur substantial liabilities to comply with climate control legislation and regulatory initiatives. Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases," may be contributing to warming of the Earth's atmosphere. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of fossil fuels, are examples of greenhouse gases. In response to such studies, the U.S. Congress is actively considering legislation and more than a dozen states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and regional greenhouse gas cap and trade programs. Moreover, the U.S. Supreme Court recently held in the case styled Massachusetts, et al. v. EPA, that greenhouse gases fall within the federal Clean Air Act's definition of "air pollutant," which could result in the regulation of greenhouse gas emissions from stationary sources under certain federal Clean Air Act programs. New legislation or regulatory programs that restrict emissions of greenhouse gases in areas in which we conduct business could have an adverse affect on our operations and demand for our services.

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

The information required for this item is provided in Note 1, Organization and Summary of Significant Accounting Policies, Note 3, Acquisitions, and Note 11, Subsequent Events included in the notes to the unaudited condensed consolidated financial statements included under Part I, Item 1, which information is incorporated by reference into this item.

Item 6. Exhibits

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

Exhibit 10.1 – Consulting Services Agreement with William E. Joor III

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

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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

August 8, 2008	/s/ Lawrence B. Connors Lawrence B. Connors Senior Vice President, Finance and Chief Accounting Officer (Duly Authorized Officer)