Regency Energy Partners LP
Form 10-Q
August 10, 2009

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, 2009

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.)
2001 BRYAN STREET, SUITE 3700 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. þYes oNo

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). oYes oNo

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer, accelerated filer and small reporting company" in Rule 12b-2 of the Exchange Act.
þLarge accelerated filer oAccelerated filer oNon-accelerated filer (Do not check if a smaller reporting company) oSmaller reporting company

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). oYes þNo

The issuer had 81,131,978 common units outstanding as of July 31, 2009.

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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. 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
Alinda	Alinda Capital Partners LLC, a Delaware limited liability company that is an independent private investment firm specializing in infrastructure investments
Alinda Investor I	Alinda Gas Pipelines I, L.P., a Delaware limited partnership
Alinda Investor II	Alinda Gas Pipelines II, L.P., a Delaware limited partnership
Alinda Investors	Alinda Investor I and Alinda Investor II, collectively
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
EITF	Emerging Issues Task Force
El Paso	El Paso Field Services, LP
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Finance Corp.	Regency Energy Finance Corp., a wholly-owned subsidiary of the Partnership
FrontStreet	FrontStreet Hugoton LLC
FSP	Financial Accounting Standards Board Statement of Position
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
HPC	RIGS Haynesville Partnership Co., a general partnership that owns 100 percent of RIGS
Lehman	Lehman Brothers Holdings, Inc.
LIBOR	London Interbank Offered Rate
LITP	Long-Term Incentive Plan
MMbtu	One million BTUs
MMbtu/d	One million BTUs per day
MMcf	One million cubic feet
MMcf/d	One million cubic feet per day
Nexus	Nexus Gas Holdings, LLC
NOE	Notice of Enforcement
NGLs	Natural gas liquids
Nasdaq	Nasdaq Stock Market, LLC

NYMEX	New York Mercantile Exchange
Partnership	Regency Energy Partners LP
Regency HIG	Regency Haynesville Intrastate Gas LLC, a wholly owned subsidiary of the Partnership
RFS	Regency Field Services LLC
RGS	Regency Gas Services LP
RIGS	Regency Intrastate Gas LP
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

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 cannot 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:

- volatility in the price of oil, natural gas, and natural gas liquids;
- declines in the credit markets and the availability of credit for us as well as for producers connected to our system and our customers;
- the level of creditworthiness of, and performance by, our counterparties and customers;
- our access to capital to fund organic growth projects and acquisitions, and our ability to obtain debt or equity financing on satisfactory terms;
- our use of derivative financial instruments to hedge commodity and interest rate risks;
- the amount of collateral required to be posted from time to time in our transactions;
- changes in commodity prices, interest rates, and demand for our services;
- changes in laws and regulations impacting the midstream sector of the natural gas industry;
- weather and other natural phenomena;
- industry changes including the impact of consolidations and changes in competition;
- our ability to obtain required approvals for construction or modernization of our facilities and the timing of production from such facilities; and
- the effect of accounting pronouncements issued periodically by accounting standard setting boards.

If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may differ materially from those anticipated, estimated, projected or expected.

Other factors that could cause our actual results to differ from our projected results are discussed in Item 1A of our December 31, 2008 Annual Report on Form 10-K.

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.

Item 1. Financial Statements

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

	June 30, 2009	December 31, 2008
ASSETS		
Current Assets:		
Cash and cash equivalents	$9,275	$599
Restricted cash	1,510	10,031
Trade accounts receivable, net of allowance of $1,565 and $941	28,637	40,875
Accrued revenues	62,013	96,712
Related party receivables	4,030	855
Assets from risk management activities	40,231	73,993
Other current assets	13,131	13,338
Total current assets	158,827	236,403
Property, Plant and Equipment:		
Gathering and transmission systems	453,169	652,267
Compression equipment	821,981	799,527
Gas plants and buildings	154,561	156,246
Other property, plant and equipment	154,570	167,256
Construction-in-progress	99,431	154,852
Total property, plant and equipment	1,683,712	1,930,148
Less accumulated depreciation	(225,881)	(226,594)
Property, plant and equipment, net	1,457,831	1,703,554
Other Assets:		
Investment in unconsolidated subsidiary	400,023	-
Long-term assets from risk management activities	13,712	36,798
Other, net of accumulated amortization of debt issuance costs of $7,706 and $5,246	22,220	13,880
Total other assets	435,955	50,678
Intangible Assets and Goodwill:		
Intangible assets, net of accumulated amortization of $27,666 and $22,667	196,557	205,646
Goodwill	228,114	262,358
Total intangible assets and goodwill	424,671	468,004
TOTAL ASSETS	$2,477,284	$2,458,639
LIABILITIES & PARTNERS' CAPITAL AND NONCONTROLLING INTEREST		
Current Liabilities:		
Trade accounts payable	$37,224	$65,483
Accrued cost of gas and liquids	48,353	76,599
Related party payables	1,331	-
Escrow payable	1,506	10,031
Deferred revenue, including related party amounts of $231 and $0	11,196	11,572

Liabilities from risk management activities	17,193	42,691
Other current liabilities	11,703	10,574
Total current liabilities	128,506	216,950
Long-term liabilities from risk management activities	53	560
Other long-term liabilities	14,820	15,487
Long-term debt, net	1,185,385	1,126,229
Commitments and contingencies		
Partners' Capital and Noncontrolling Interest:		
Common units (81,781,105 and 55,519,903 units authorized; 81,131,978 and 54,796,701 units issued and outstanding at June 30, 2009 and December 31, 2008)	1,079,333	764,161
Class D common units (7,276,506 units authorized, issued and outstanding at December 31, 2008)	-	226,759
Subordinated units (19,103,896 units authorized, issued and outstanding at December 31, 2008)	-	(1,391)
General partner interest	24,864	29,283
Accumulated other comprehensive income	30,304	67,440
Noncontrolling interest	14,019	13,161
Total partners' capital and noncontrolling interest	1,148,520	1,099,413
TOTAL LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST	$2,477,284	$2,458,639

See accompanying notes to condensed consolidated financial statements

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
REVENUES				
Gas sales	$106,897	$362,769	$254,793	$599,462
NGL sales	57,676	126,521	107,261	235,020
Gathering, transportation and other fees, including related party amounts of $2,239, $935, $3,376 and $1,926	69,231	70,175	142,079	132,161
Net realized and unrealized gain (loss) from risk management activities	12,515	(32,760)	26,970	(46,417)
Other	7,223	20,000	12,417	31,714
Total revenues	253,542	546,705	543,520	951,940
OPERATING COSTS AND EXPENSES				
Cost of sales, including related party amounts of $1,453, $844, $1,700 and $1,247	157,347	446,687	339,875	760,276
Operation and maintenance	31,974	32,516	68,016	61,361
General and administrative	14,127	13,925	29,205	24,809
Loss (gain) on asset sales, net of costs of $372, $0, $5,530 and $0	651	442	(133,280)	468
Management services termination fee	-	-	-	3,888
Transaction expenses	-	147	-	534
Depreciation and amortization	26,236	26,476	54,125	48,216
Total operating costs and expenses	230,335	520,193	357,941	899,552
OPERATING INCOME	23,207	26,512	185,579	52,388
Income from unconsolidated subsidiary	1,587	-	1,923	-
Interest expense, net	(19,568)	(16,782)	(33,795)	(32,188)
Other income and deductions, net	214	132	256	332
INCOME BEFORE INCOME TAXES	5,440	9,862	153,963	20,532
Income tax expense (benefit)	(515)	(41)	(416)	209
NET INCOME	5,955	9,903	154,379	20,323
Net loss (income) attributable to noncontrolling interest	(65)	69	(100)	(3)
NET INCOME ATTRIBUTABLE TO REGENCY ENERGY PARTNERS LP	$5,890	$9,972	$154,279	$20,320
General partner's interest, including IDR	741	727	4,274	1,634
Allocation of net income to non-vested common units	(137)	71	1,217	163

Beneficial conversion feature for Class D common units	-	1,866	820	3,425
Limited partners' interest	$5,286	$7,308	$147,968	$15,098
Basic and Diluted earnings per unit:				
Amount allocated to common and subordinated units	$5,286	$7,308	$147,968	$15,098
Weighted average number of common and subordinated units outstanding	80,550,149	62,175,856	78,920,074	60,702,682
Basic income per common and subordinated unit	$0.07	$0.12	$1.87	$0.25
Diluted income per common and subordinated unit	$0.06	$0.12	$1.85	$0.25
Distributions per unit	$0.445	$0.445	$0.89	$0.865
Amount allocated to Class D common units	$-	$1,866	$820	$3,425
Total number of Class D common units outstanding	-	7,276,506	7,276,506	7,276,506
Income per Class D common unit due to beneficial conversion feature	$-	$0.26	$0.11	$0.47
Distributions per unit	$-	$-	$-	$-

See accompanying notes to condensed consolidated financial statements

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Net income	$5,955	$9,903	$154,379	$20,323
Net hedging amounts reclassified to earnings	(13,644)	15,167	(27,894)	25,602
Net change in fair value of cash flow hedges	(14,622)	(47,071)	(9,242)	(49,905)
Comprehensive income (loss)	$(22,311)	$(22,001)	$117,243	$(3,980)
Comprehensive (income) loss attributable to noncontrolling interest	(65)	69	(100)	(3)
Comprehensive income (loss) attributable to Regency Energy Partners LP	$(22,376)	$(21,932)	$117,143	$(3,983)

See accompanying notes to condensed consolidated financial statements

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

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
OPERATING ACTIVITIES		
Net income	$154,379	$20,323
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization, including debt issuance cost amortization	56,750	49,598
Noncash income from unconsolidated subsidiary	(23)	-
Risk management portfolio valuation changes	(6,293)	20,582
Loss (gain) on asset sales, net	(133,280)	468
Unit based compensation expenses	2,750	1,839
Cash flow changes in current assets and liabilities:		
Trade accounts receivable, accrued revenues, and related party receivables	38,073	(72,784)
Other current assets	3,728	(2,914)
Trade accounts payable, accrued cost of gas and liquids, and related party payables	(38,809)	53,088
Other current liabilities	(7,396)	15,314
Other assets and liabilities	(608)	1,420
Net cash flows provided by operating activities	69,271	86,934
INVESTING ACTIVITIES		
Capital expenditures	(119,185)	(148,888)
Acquisitions	-	(577,345)
Proceeds from asset sales	83,182	580
Net cash flows used in investing activities	(36,003)	(725,653)
FINANCING ACTIVITIES		
Net (repayments) borrowings under revolving credit facilities	(177,249)	681,000
Proceeds from issuance of senior notes, net of discount	236,240	-
Debt issuance costs	(11,939)	(3,313)
Partner contributions	-	7,663
Partner distributions	(71,644)	(52,317)
Proceeds from option exercises	-	2,700
Net cash flows (used in) provided by financing activities	(24,592)	635,733
Net increase (decrease) in cash and cash equivalents	8,676	(2,986)
Cash and cash equivalents at beginning of period	599	32,971
Cash and cash equivalents at end of period	$9,275	$29,985
Supplemental cash flow information:		
Interest paid, net of amounts capitalized	$28,374	$28,222
Income taxes paid	-	564
Non-cash capital expenditures in accounts payable	9,480	17,907

Issuance of common units for an acquisition	-	219,590
Contribution of fixed assets, goodwill and working capital to RIGS Haynesville Partnership Co.	261,019	-

See accompanying notes to condensed consolidated financial statements

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

	Regency Energy Partners LP								
	Units								
	Common	Class D	Subordinated	Common Unitholders	Class D Unitholders	Subordinated Unitholders	General Partner Interest	Accumulated Other Comprehensive Income	Noncontrolling Interest
Balance - December 31, 2008	54,796,701	7,276,506	19,103,896	$764,161	$226,759	$(1,391)	$29,283	$67,440	$13,161
Revision of partner interest	-	-	-	6,073	-	-	(6,073)	-	
Issuance of non-vested common units, net of forfeitures	(45,125)	-	-	-	-	-	-	-	-
Conversion of subordinated units	19,103,896		(19,103,896)	(1,391)	-	1,391	-	-	-
Unit based compensation expenses	-	-	-	2,750	-	-	-	-	-
Partner distributions	-	-	-	(69,024)	-	-	(2,620)	-	-
Net income	-	-	-	149,185	820	-	4,274	-	100
Conversion of Class D common units	7,276,506	(7,276,506)	-	227,579	(227,579)	-	-	-	-
Contributions from noncontrolling interest	-	-	-	-	-	-	-	-	758
Net hedging amounts reclassified to earnings	-	-	-	-	-	-	-	(27,894)	-
Net change in fair value of cash flow hedges	-	-	-	-	-	-	-	(9,242)	-
Balance - June 30, 2009	81,131,978	-	-	$1,079,333	$-	$-	$24,864	$30,304	$14,019

See accompanying notes to condensed consolidated financial statements

Regency Energy Partners LP
Notes to Unaudited Condensed Consolidated Financial Statements

1. Organization and Summary of Significant Accounting Policies
Organization. The unaudited condensed consolidated financial statements presented herein contain the results of Regency Energy Partners LP and its subsidiaries. The Partnership and its subsidiaries are engaged in the business of gathering and processing, contract compression, and transporting of natural gas and NGLs.

The unaudited financial information as of, and for the three and six months ended June 30, 2009 has been prepared on the same basis as the audited consolidated financial statements included in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2008, as amended by Form 8-K filed on May 14, 2009. 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.

Equity Method Investments. The equity method of accounting is used to account for the Partnership's interest in investments greater than 20 percent voting stock of an investee and where the Partnership lacks control over the investee.

Intangible Assets. Intangible assets, net consist of the following.

	Permits and Licenses	Customer Contracts	Trade Names	Customer Relations	Total
			(in thousands)		
Balance at December 31, 2008	$ 8,582	$ 126,799	$ 32,848	$ 37,417	$ 205,646
Disposals	(2,920)	-	-	-	(2,920)
Amortization	(313)	(3,612)	(1,170)	(1,074)	(6,169)
Balance at June 30, 2009	$ 5,349	$ 123,187	$ 31,678	$ 36,343	$ 196,557

The weighted average amortization period for permits and licenses, customer contracts, trade names, and customer relations are 15, 24, 15, and 19 years, respectively. Permits and licenses are generally renewed with minimal expense as a charge to operating and maintenance expense in the period incurred. Regarding customer contracts, the actual remaining lives of the contracts were used to evaluate the cash flows expected with no renewal assumption. The trade name and customer relations intangible assets use the going concern assumption with no renewal cost. The expected amortization of the intangible assets for each of the five succeeding years is as follows.

Year ending December 31,	Total
	(in thousands)
	$ 6,043

2009 (remaining)	
2010	12,086
2011	10,828
2012	10,535
2013	10,535

Revision to Partners' Capital Accounts. In 2009, the Partnership revised the allocation of net income between the general partner and common unit holders from a previous period to reflect the income allocation provisions of the Partnership agreement. The effect of this revision is not material to the prior financial statements.

Recently Issued Accounting Standards. In December 2007, the FASB issued SFAS No. 141(R), "Business Combinations" ("SFAS 141(R)"), which significantly changes the accounting for business acquisitions both during the period of the acquisition and in subsequent periods. The Partnership adopted SFAS 141(R) on January 1, 2009.

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51" ("SFAS 160"), which significantly changes the accounting and reporting related to noncontrolling interests in a consolidated subsidiary. The Partnership adopted SFAS 160 for all periods presented. This statement requires the recognition of a noncontrolling interest (formerly styled as a minority interest) in partners' capital in the condensed consolidated financial statements and separate from the partners' interest. Also, the amount of net income attributable to the noncontrolling interest is included in the consolidated net income on the face of the condensed consolidated income statement.

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"). EITF 07-4 defines how to allocate net income among the various classes of equity, including incentive distribution rights (or "IDRs"), narrowing the number of currently acceptable methods. The standard became effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Earlier application was not permitted, and EITF 07-4 must be applied retrospectively for all financial statements presented. The adoption of this standard changes the Partnership's method of allocating net income for earnings per unit purposes to holders of the IDRs in periods where net income exceeds cash distributed. Because the Partnership Agreement restricts the amount of distributions to holders of IDRs based on cash available for distribution, undistributed net income will be allocated based on each class of security's ownership interest. Further, because the IDR's are deemed to have no ownership interest, no undistributed net income will be allocated to this class of security. All prior period earnings per unit data have been adjusted.

In April 2008, FASB issued FSP No. 142-3, "Determination of the Useful Life of Intangible Assets" ("FSP 142-3"), which amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of intangible assets. The objective of FSP 142-3 is to better match the useful life of intangible assets to the cash flow generated. FSP 142-3 became effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those fiscal years. The adoption of FSP 142-3 did not impact the Partnership's financial position, results of operations or cash flows.

In May 2008, the FASB issued SFAS No. 162, "The Hierarchy of Generally Accepted Accounting Principles" ("SFAS 162"), which identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements that are presented in conformity of GAAP. SFAS 162's effective date is November 15, 2008. The adoption of SFAS 162 had no 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" ("FSP EITF 03-6-1") and is effective for fiscal years beginning after December 15, 2008. The adoption of this standard was applied retrospectively and had an immaterial impact on the Partnership's earnings per unit.

In April 2009, the FASB issued FSP FAS 107-1, "Interim Disclosures about Fair Value of Financial Instruments," which is effective for interim periods ending after June 15, 2009. The adoption of this standard, which requires publicly traded companies to make fair value disclosures in interim periods, had no impact on the Partnership's financial position, results of operations or cash flows.

In May 2009, the FASB issued SFAS No. 165, "Subsequent Events" ("SFAS 165"), which requires public entities to evaluate subsequent events through the date through which financial statements are issued. SFAS 165 is effective for interim and annual periods ending after June 15, 2009. The adoption of SFAS 165 did not impact the Partnership's financial position, results of operations or cash flows.

In June 2009, the FASB issued SFAS No. 167, "Amendments to FASB Interpretation No. 46(R) ("FASB 167"), which significantly changes the consolidation model for variable interest entities. SFAS 167 shall be effective for annual reporting period that begins after November 15, 2009, and for interim periods within that first annual reporting period. The Partnership is currently evaluating the potential impact of this standard on its financial position, results of operations or cash flows.

In June 2009, the FASB issued SFAS No. 168, "The FASB Accounting Standards Codification TM and the Hierarchy of Generally Accepted Accounting Principles, a replacement of SFAS No. 162" (the "Codification"). The Codification will be the single source for GAAP that integrates existing standards and organizes them into accounting topics. The Codification is not intended to change GAAP but will change how GAAP is referenced in the financial statements. The Codification will become effective for financial statements issued for interim and annual periods ending after September 15, 2009, and it is not expected to have a material impact on the Partnership's financial position, results of operations or cash flows.

2. Income per Limited Partner Unit

The Partnership issued 7,276,506 Class D common units in connection with the CDM acquisition. 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 Class D common units converted to common units on a one-for-one basis on February 9, 2009.

The following tables provide a reconciliation of the basic and diluted earnings per unit computations.

	For the Three Months Ended June 30, 2009			For the Three 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						
Net income attributable to Limited Partner interests	$5,286	80,550,149	$0.07	$7,308	62,175,856	$0.12
Effect of Dilutive Securities						
Non-vested common units	(137)	621,337		71	705,145	
Diluted Earnings per Unit	$5,149	81,171,486	$0.06	$7,379	62,881,001	$0.12

	For the Six Months Ended June 30, 2009			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						
Net income attributable to Limited Partner interests	$147,968	78,920,074	$1.87	$15,098	60,702,682	$0.25
Effect of Dilutive Securities						
Non-vested common units	1,217	652,740		-	-	
Common unit options	-	-		-	149,186	
Class D common units	820	1,608,068		-	-	
Diluted Earnings per Unit	$150,005	81,180,882	$1.85	$15,098	60,851,868	$0.25

The following table shows securities that could potentially dilute earnings per unit in the future that were not included in the computation of diluted earnings per unit because to do so would have been antidilutive.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Non-vested common units	-	-	-	713,925
Common unit options	372,768	-	376,518	-
Class D common units	-	7,276,506	-	7,276,506

Phantom units	332,860	-	332,860	-

3. Acquisitions and Disposition

On March 17, 2009, the Partnership announced the completion of the transactions contemplated by the Contribution Agreement (the “Contribution Agreement”) relating to a new joint venture arrangement among Regency HIG, EFS Haynesville, LLC, a 100 percent owned subsidiary of GECC, and the Alinda Investors. The Partnership contributed RIGS, which owns the Regency Intrastate Gas System, valued at $400,000,000, to HPC, in exchange for a 38 percent interest in HPC. EFS Haynesville, LLC and the Alinda Investors contributed $126,500,000 and $526,500,000 in cash, respectively, to HPC in return for a 12 percent and a 50 percent interest, respectively. In accordance with SFAS 160, the disposition and deconsolidation resulted in the recording of a $133,451,000 gain (of which $52,813,000 represents the remeasurement of the Partnership’s retained 38 percent interest to its fair value), net of transaction costs of $5,530,000.

The following unaudited pro forma financial information has been prepared as if the acquisitions of FrontStreet, CDM and Nexus and the contribution of RIGS to HPC had occurred as of the beginning of the earliest period presented. Such unaudited pro forma financial 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		Pro Forma Results for the Six Months Ended	
	June 30, 2009	June 30, 2008	June 30, 2009	June 30, 2008
	(in thousands except unit and per unit data)			
Revenue	$253,542	$535,344	$531,547	$935,793
Net income attributable to Regency Energy Partners LP	$5,890	$1,542	$16,325	$143,608
Less:				
General partner's interest, including IDR	741	559	1,515	4,101
Allocation of net income to non-vested common units	(137)	(8)	30	1,588
Beneficial conversion feature for Class D common units	-	1,866	820	3,425
Limited partners' interest	$5,286	$(875)	$13,960	$134,494
Basic and Diluted earnings per unit:				
Amount allocated to common and subordinated units	$5,286	$(875)	$13,960	$134,494
Weighted average number of common and subordinated units outstanding	80,550,149	62,175,856	78,920,074	60,702,682
Basic income (loss) per common and subordinated unit	$0.07	$(0.01)	$0.18	$2.22
Diluted income per common and subordinated unit	$0.06	-	$0.18	$1.93
Distributions per unit	$0.445	$0.445	$0.89	$0.865
Amount allocated to Class D common units	$-	$1,866	$820	$3,425
Total number of Class D common units outstanding	-	7,276,506	7,276,506	7,276,506
Basic and diluted income per Class D common unit due to beneficial conversion feature	$-	$0.26	$0.11	$0.47
Distributions per unit	$-	$-	$-	$-

4. Investment in Unconsolidated Subsidiary

As described in the Acquisitions and Disposition footnote, the Partnership contributed RIGS to HPC for a 38 percent partner interest in HPC. The summarized financial information of HPC as of June 30, 2009 and for the period from inception (March 18, 2009) to June 30, 2009 is disclosed below. The Partnership recognized $1,923,000 in income from unconsolidated subsidiary for its 38 percent ownership interest from inception (March 18, 2009) to June 30, 2009.

RIGS Haynesville Partnership Co.
Condensed Consolidated Balance Sheet
Unaudited
(in thousands)

	June 30, 2009
ASSETS	
Total current assets	$365,623
Property, plant and equipment, net	682,094
Total other assets	55,905
TOTAL ASSETS	$1,103,622
LIABILITIES & PARTNERS' CAPITAL	
Total current liabilities	$50,560
Partners' capital	1,053,062
TOTAL LIABILITIES & PARTNERS' CAPITAL	$1,103,622

Condensed Income Statement
From Inception (March 18, 2009) to June 30, 2009
Unaudited
(in thousands)

	Three Months Ended June 30, 2009	From Inception (March 18, 2009) to June 30, 2009
Total revenues	$ 11,707	$ 13,533
Total operating costs and expenses	8,038	9,084
OPERATING INCOME	3,669	4,449
Other income and deductions, net	508	612
NET INCOME	$ 4,177	$ 5,061

5. Risk Management Activities

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133" ("SFAS 161"). SFAS 161 requires enhanced disclosures about derivative and hedging activities. The Partnership adopted this standard as of January 1, 2009 and its adoption had no impact on its financial position, results of operations or cash flows.

Risk and Accounting Policies. The Partnership established comprehensive risk management policies and procedures to monitor and manage the market risks associated with commodity prices, counterparty credit, and interest rates. The Partnership's General Partner is responsible for delegation of transaction authority levels, and the Risk Management Committee of the General Partner is responsible for the overall management of these risks, including monitoring exposure limits. The Risk Management Committee receives regular briefings on positions and exposures, credit exposures, and overall risk management in the context of market activities.

The Partnership primarily deals with financial institutions when entering into financial derivatives.

Commodity Price Risk. The Partnership is exposed to the impact of market fluctuations in the prices of natural gas, NGLs, and other commodities as a result of our gathering and processing activities, and the Partnership is a net seller of natural gas, NGLs and condensate. The Partnership attempts to mitigate commodity price risk exposure by matching pricing terms between its purchases and sales of commodities. To the extent that the Partnership sells commodities in which pricing terms cannot be matched and there is a substantial risk of price exposure, the Partnership attempts to use financial hedges to mitigate the risk. It is the Partnership's policy not to take any speculative positions with their derivative contracts. In some cases, the Partnership may not be able to match pricing terms or to cover its risk to price exposure with financial hedges, and it may be exposed to commodity price risk.

Both the Partnership's profitability and cash flows are affected by volatility in prevailing natural gas and NGL prices. Natural gas and NGL prices are impacted by changes in the supply and demand for NGLs and natural gas, as well as market uncertainty. Adverse effects on cash flows from reductions in natural gas and NGL product prices could adversely affect the Partnership's ability to make distributions to unitholders. The Partnership manages this commodity price exposure through an integrated strategy that includes management of its contract portfolio, matching sales prices of commodities with purchases, optimization of our portfolio by monitoring basis and other price differentials in operating areas, and the use of derivative contracts.

The Partnership has executed swap contracts settled against condensate, ethane, propane, butane, natural gas, and natural gasoline market prices. The Partnership hedged its expected exposure to declines in prices for natural gas, NGLs and condensate volumes produced for its account in the approximate percentages set for below:

	As of June 30, 2009		As of July 31, 2009		
	2009	2010	2009	2010	2011
NGLs	97%	37%	97%	56%	18%
Condensate	76%	76%	76%	76%	18%
Natural gas	85%	44%	85%	44%	0%

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. The swaps continued to serve as economic hedges against price exposure for the Partnership. At June 30, 2009, the Partnership has the following commodity swaps that qualify as cash flow hedges: the 2009 NGLs, natural gas and West Texas Intermediate crude oil hedging programs and the 2010 natural gas and West Texas Intermediate crude oil hedging programs.

In March 2008, the Partnership entered offsetting trades against its existing 2009 NGL portfolio of mark-to-market hedges, which it believes will substantially reduce the volatility of its 2009 NGL hedges. This group of trades, along with the pre-existing 2009 NGL portfolio, will continue to be accounted for on a mark-to-market basis. Simultaneously, the Partnership executed additional 2009 NGL swaps which were designated as cash flow hedges. In May 2008, the Partnership entered into commodity swaps to hedge a portion of its 2010 NGL commodity risk, except for ethane, which are accounted for using the mark-to-market accounting treatment.

The Partnership accounts for a portion of its West Texas Intermediate crude oil swaps using mark-to-market accounting. In August 2008, the Partnership entered into an offsetting trade against its existing 2009 West Texas Intermediate crude oil swap to minimize the volatility of the original 2009 swap. Simultaneously, the Partnership executed an additional 2009 West Texas Intermediate crude oil swap, which was designated as a cash flow hedge. In May 2008, the Partnership entered into a West Texas Intermediate crude oil swap to hedge its 2010 condensate price risk, which was designated as a cash flow hedge.

In December 2008, the Partnership entered into two natural gas swaps to hedge its equity exposure to natural gas for 2009. These natural gas swaps were designated as cash flow hedges.

In May 2009, the Partnership entered into a natural gas swap to hedge a portion of its equity exposure to natural gas for 2010. This natural gas swap was designated as a cash flow hedge.

In July 2009, the Partnership entered offsetting trades against half of its existing 2010 NGL portfolio of mark-to-market hedges, which it believes will substantially reduce the volatility of its 2010 NGL hedges. This group of trades, along with the pre-existing 2010 NGL portfolio, will continue to be accounted for on a mark-to-market basis. Simultaneously, the Partnership executed additional 2010 NGL swaps which were designated as cash flow hedges.

Additionally, in July 2009, the Partnership entered into swap transactions to hedge a portion of its forecasted NGLs and condensate equity exposure for the first half of 2011. These swaps are accounted for using the mark-to-market accounting treatment.

Interest Rate Risk. The Partnership is exposed to variable interest rate risk as a result of borrowings under its existing credit facility. As of June 30, 2009, the Partnership had $591,479,000 of outstanding long-term balances exposed to variable interest rate risk. An increase of 100 basis points in the LIBOR rate would increase the Partnership's annual payment by $5,915,000. 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 (3 percent as of June 30, 2009) through March 5, 2010. These interest rate swaps were designated as cash flow hedges.

Credit Risk. The Partnership's resale of natural gas exposes it to credit risk, as the margin on any sale is generally a very small percentage of the total sales price. Therefore a credit loss can be very large relative to overall profitability on these transactions. The Partnership attempts to ensure that it issues credit only to credit-worthy counterparties and that in appropriate circumstances any such extension of credit is backed by adequate collateral such as a letter of credit or a parental guarantee.

The Partnership is exposed to credit risk from its derivative counterparties. The Partnership does not require collateral from these counterparties. The Partnership has entered into Master International Swap Dealers Association ("ISDA") Agreements that allow for netting of swap contract receivables and payables in the event of default by either party. If the Partnership's counterparties failed to perform under existing swap contracts, the Partnership's maximum loss is $54,733,000, which would be reduced by $13,666,000 due to the netting feature. The Partnership has elected to present assets and liabilities under Master ISDA Agreements gross on the condensed consolidated balance sheet.

Quantitative Disclosures. The Partnership expects to reclassify $27,334,000 of net hedging gains to revenues or interest expense from accumulated other comprehensive income in the next twelve months.

The Partnership's risk management activities assets and liabilities, including its SFAS No. 157, "Fair Value Measurements" ("SFAS 157") credit risk adjustment, are detailed below for the periods ended June 30, 2009 and December 31, 2008.

	Assets		Liabilities	
	June 30, 2009	December 31, 2008	June 30, 2009	December 31, 2008
	(in thousands)			
Derivatives designated as cash flow hedges				
Current amounts from risk management activities				
Interest rate contracts	$ -	$ -	$ 3,767	$ 4,680
Commodity contracts	30,487	59,882	54	-
Long-term amounts from risk management activities				
Interest rate contracts	-	-	-	560
Commodity contracts	5,312	13,373	53	-
Total cash flow hedging instruments	35,799	73,255	3,874	5,240
Derivatives not designated as cash flow hedges				
Current amounts from risk management activities				
Interest rate contracts	-	-	-	-
Commodity contracts	10,534	16,001	13,612	38,402

Long-term amounts from risk management activities				
Interest rate contracts	-	-	-	-
Commodity contracts	8,400	23,425	-	-
Total derivatives not designated as cash flow hedges	18,934	39,426	13,612	38,402
SFAS 157 Credit Risk Assessment				
Current amounts from risk management activities	(790)	(1,890)	(240)	(391)
Total derivatives	$ 53,943	$ 110,791	$ 17,246	$ 43,251

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The Partnership's condensed consolidated statement of accumulated other comprehensive income (loss) and condensed consolidated income statements for the periods ended June 30, 2009 and 2008 were impacted by risk management activities as follows (in thousands).

Derivatives designated as cash flow hedges

	Three Months Ended June 30, 2009			Three Months Ended June 30, 2008		
	Interest Rate	Commodity	Total	Interest Rate	Commodity	Total
Gain (loss) recognized in accumulated OCI (Effective)	$(676)	$(13,946)	$(14,622)	$4,865	$(51,936)	$(47,071)
Gain (loss) reclassified from accumulated OCI into income (Effective)	(1,515)	15,546	14,031	171	(15,277)	(15,106)
Gain recognized in income (Ineffective)	-	1,616	1,616	-	262	262

	Six Months Ended June 30, 2009			Six Months Ended June 30, 2008		
	Interest Rate	Commodity	Total	Interest Rate	Commodity	Total
Gain (loss) recognized in accumulated OCI (Effective)	$(1,514)	$(7,728)	$(9,242)	4,444	(54,349)	$(49,905)
Gain (loss) reclassified from accumulated OCI into income (Effective)	(2,987)	32,065	29,078	359	(25,844)	(25,485)
Gain recognized in income (Ineffective)	-	2,231	2,231	-	486	486

Derivatives not designated as cash flow hedges

	Three Months Ended June 30, 2009			Three Months Ended June 30, 2008		
	Interest Rate	Commodity	Total	Interest Rate	Commodity	Total
Loss from dedesignation amortized from accumulated OCI into income	$-	$(387)	$(387)	$-	$(61)	$(61)
Loss recognized in income	-	(5,690)	(5,690)	-	(18,632)	(18,632)

	Six Months Ended June 30, 2009			Six Months Ended June 30, 2008		
	Interest Rate	Commodity	Total	Interest Rate	Commodity	Total
Loss from dedesignation amortized from accumulated OCI into income	$-	$(1,184)	$(1,184)	$-	$(117)	$(117)
Loss recognized in income	-	(7,092)	(7,092)	-	(21,890)	(21,890)

Credit risk assessment for commodity and interest rate swaps

	Three Months Ended		Six Months Ended	
	June 30, 2009	June 30, 2008	June 30, 2009	June 30, 2008
Gain recognized in income	$1,430	$948	$950	$948

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6. Long-term Debt, net

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

	June 30, 2009	December 31, 2008
	(in thousands)	
Senior notes	$593,906	$357,500
Revolving loans	591,479	768,729
Total	1,185,385	1,126,229
Less: current portion	-	-
Long-term debt	$1,185,385	$1,126,229
Availability under revolving credit facility:		
Total credit facility limit	$900,000	$900,000
Unfunded Lehman commitments	(7,030)	(8,646)
Revolving loans	(591,479)	(768,729)
Letters of credit	(16,257)	(16,257)
Total available	$285,234	$106,368

On May 20, 2009, the Partnership and Finance Corp. issued $250,000,000 senior notes in a private placement that mature on June 1, 2016. The senior notes bear interest at 9.375 percent with interest payable semiannually on June 1 and December 1. The proceeds were used to partially repay revolving loans under the Partnership's credit facility.

The Partnership has a commitment to register the 9.375 percent senior notes due 2016 by May 2010. Failure to do so would result in a registration default. For the first 90 day period beyond the registration default, the Partnership would be required to pay .25 percent of the face amount of the notes as liquidated damages until the default is cured. The rate of liquidated damages would increase by an additional .25 percent for each subsequent 90 day period of the registration default, with a maximum amount of liquidated damages of 1.0 percent per year. The Partnership's management expects to be able to register the notes in a timely manner, and accordingly has not recognized a liability for this registration payment arrangement.

At any time before June 1, 2012, up to 35 percent of the senior notes can be redeemed at a price of 109.375 percent plus accrued interest and liquidated damages. On or after June 1, 2013, all or part of the senior notes can be redeemed at a price of 100 percent plus accrued interest and liquidated damages. At any time prior to June 1, 2013, the Partnership may also redeem all or part of the notes at a price equal to 100 percent of the principal amount of notes redeemed plus accrued interest, liquidated damages, and the applicable premium, which equals to the greater of (1) 1 percent of the principal amount of the note; or (2) the excess of the present value at such redemption date of (i) the redemption price of the note at June 1, 2013 plus (ii) all required interest payments due on the note through June 1, 2013, computed using a discount rate equal to the Treasury Rate as of such redemption date plus 50 basis points; over the principal amount of the note.

Upon change of control each note holder will be entitled to require the Partnership to purchase all or a portion of its notes at a purchase price of 101 percent plus accrued interest and liquidated damages. The senior notes contain various covenants that limit, among other things, the Partnership's ability and the ability of certain of its subsidiaries to:

- incur additional indebtedness;
- pay distributions on, or repurchase or redeem equity interests;
- make certain investments;

- incur liens;
- enter into certain types of transactions with affiliates; and
- sell assets, consolidate or merge with or into other companies.

The senior notes are jointly and severally guaranteed by all of the Partnership's current consolidated subsidiaries, other than Finance Corp., and by certain of its future subsidiaries. The senior notes and the guarantees are unsecured and rank equally with all of the Partnership's and the guarantors' existing and future unsubordinated obligations. The senior notes and the guarantees will be senior in right of payment to any of the Partnership's and the guarantors' future obligations that are, by their terms, expressly subordinated in right of payment to the notes and the guarantees. The senior notes and the guarantees will be effectively subordinated to the Partnership's and the guarantors' secured obligations, including the Partnership's Credit Facility, to the extent of the value of the assets securing such obligations.

Finance Corp. has no operations and will not have revenue other than as may be incidental as co-issuer of the senior notes. Since the Partnership has no independent operations, the guarantees are fully unconditional and joint and several of its subsidiaries, except certain wholly owned subsidiaries, the Partnership has not included condensed consolidated financial information of guarantors of the senior notes.

The unamortized balance of the discount on the Partnership's senior notes due 2016 is as follows.

	June 30, 2009	December 31, 2008
	(in thousands)	
Principal amount	$250,000	$-
Less: unamortized discount	(13,594)	-
	$236,406	$-

On March 17, 2009, RGS amended its credit agreement to authorize the contribution of RIGS to a joint venture (HPC) and allow for future investment up to $135,000,000 in a joint venture. The amendment imposed additional financial restrictions that limit the ratio of senior secured indebtedness to EBITDA. The alternate base rate used to calculate interest on base rate loans will be calculated based on the greatest to occur of a base rate, a federal funds effective rate plus 0.50 percent and an adjusted one-month LIBOR rate plus 1.50 percent. The applicable margin shall range from 1.50 percent to 2.25 percent for base rate loans, 2.50 percent to 3.25 percent for Eurodollar loans, and commitment fees will range from 0.375 percent to 0.500 percent.

On July 24, 2009, RGS further amended its credit agreement to allow for a $25,000,000 working capital facility for the RIGS Haynesville Joint Venture.

GECC Credit Facility. On February 26, 2009, the Partnership entered into a $45,000,000 unsecured revolving credit agreement with GECC. The proceeds of the GECC Credit Facility were available for expenditures made in connection with the Haynesville Expansion Project prior to the effectiveness of the above March 17, 2009 amendment. The commitments under the Revolving Credit Facility terminated on March 17, 2009. The Partnership paid a commitment fee of $2,718,000 to GECC related to this GECC Credit Facility, which was recorded as a decrease to gain on asset sales, net.

On September 15, 2008, Lehman filed a petition in the United States Bankruptcy Court seeking relief under chapter 11 of the United States Bankruptcy Code. As of June 30, 2009, the Partnership borrowed all but $7,030,000 of the amount committed by Lehman under the Credit Facility. Lehman has declined requests to honor its remaining commitment, effectively reducing the total size of the Credit Facility's capacity to $892,970,000. Further, if the Partnership makes repayments of loans against the revolving facility which were, in part, funded by Lehman, the amounts funded by Lehman may not be reborrowed.

The outstanding balance of revolving debt under the credit facility bears interest at LIBOR plus a margin or Alternate Base Rate (equivalent to the U.S prime rate 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 5.94 percent and 6.49 percent for the six months ended June 30, 2009 and 2008, respectively, and 6.69 percent and 6.12 percent for the three months ended June 30, 2009 and 2008, respectively. The senior notes pay fixed rate of interest with a weighted average rate of 8.787 percent.

7. Commitments and Contingencies
Legal. The Partnership is involved in various claims and lawsuits incidental to its business. These claims and lawsuits in the aggregate should not have a material adverse effect on the Partnership's business, financial condition, results of operations or cash flows.

Escrow Payable. At June 30, 2009, $1,510,000 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 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. This escrow amount will be further reduced under a specified schedule as El Paso completes its cleanup obligations and the remainder will be released upon completion.

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 against the Partnership or under the policy.

TCEQ Notice of Enforcement. On February 15, 2008, the TCEQ issued a NOE concerning one of the Partnership's processing plants 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 four 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, and it later reduced its settlement demand to $360,000 in July 2008. The Partnership was unable to settle this matter on a satisfactory basis and the TCEQ has referred the matter to its litigation division for further administrative proceedings.

Keyes Litigation. In August 2008, Keyes Helium Company, LLC ("Keyes") filed suit against Regency Gas Services LP, the Partnership, and the 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 its Lakin plant and contract with a third party 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. Discovery is expected to end in September 2009 and trial is scheduled for December 2009.

Kansas State Severance Tax. In August 2008, a customer began remitting severance tax to the state of Kansas based on the value of condensate purchased from one of the Partnership's Mid-Continent gathering fields and deducting the tax from its payments to the Partnership. The Kansas Department of Revenue advised the customer that it was appropriate to remit such taxes and withhold the taxes from its payments to the Partnership, absent an order or legal opinion from the Kansas Department of Revenue stating otherwise. The Partnership has requested a determination and refund from the Kansas Department of Revenue regarding the matter since severance taxes were already paid on the gas from which the condensate is collected and no additional tax is due. The Kansas Department of Revenue has initiated an audit of the Partnership's condensate sales in Kansas. If the Kansas Department of Revenue determines that the condensate sales are taxable, then the Partnership may be subject to additional taxes, interest and possibly penalties for past and future condensate sales.

Caddo Gas Gathering LLC v. Regency Intrastate Gas LLC. Caddo Gas Gathering LLC ("Caddo Gas") claims that RIGS breached a 1988 natural gas transportation agreement (the "Transportation Agreement"). Caddo Gas alleges that the Transportation Agreement requires RIGS to take receipt of gas at any receipt point on the "Regency Gas System" and redeliver that gas for $0.05 per MMbtu. It further alleges that RIGS' obligation to provide transportation to Caddo Gas is unconditional and that RIGS breached the Transportation Agreement when it refused to let Caddo Gas access a fully-subscribed receipt point interconnect at the Centerpoint Energy Sligo Plant ("Sligo Point"), but offered to install a new interconnect at Caddo Gas' cost. RIGS filed an answer denying that Caddo Gas was entitled to access the Regency Gas System through the Sligo Point and denying that its actions constituted a breach of the Transportation Agreement. No trial date has been set.

Remediation of Groundwater Contamination at Calhoun and Dubach Plants. RFS currently owns the Dubach and Calhoun gas processing plants in north Louisiana (the "Plants"). The Plants each have groundwater contamination as result of historical operations. At the time that RFS acquired the Plants from El Paso, Kerr-McGee Corporation (Kerr-McGee) was performing remediation of the groundwater contamination, because the Plants were once owned by Kerr-McGee and when Kerr-McGee sold the Plants to a predecessor of El Paso in 1988, Kerr-McGee retained liability for any environmental contamination at the Plants. In 2005, Kerr-McGee created and spun off Tronox and Tronox allegedly assumed certain Kerr-McGee's environmental remediation obligations (including its obligation to perform remediation at the Plants) prior to the acquisition of Kerr-McGee by Anadarko Petroleum Corporation. In January 2009, Tronox filed for Chapter 11 bankruptcy protection. RFS will file a claim in the bankruptcy proceeding relating to the environmental remediation work at the Plants.

8. Related Party Transactions
The employees operating the assets of the Partnership and its subsidiaries and all those providing staff or support services are employees of the General Partner. Pursuant to the Partnership Agreement, our General Partner receives a monthly reimbursement for all direct and indirect expenses incurred on behalf of the Partnership. Reimbursements of $8,591,000, $16,209,000, $8,433,000, and $15,321,000 were recorded in the Partnership's financial statements during the three and six months ended June 30, 2009 and 2008, respectively, as operation and maintenance expenses or general and administrative expenses, as appropriate.

In conjunction with distributions by the Partnership to its limited and general partner interests, during the six months ended June 30, 2009, GE EFS received cash distributions of $12,181,000 and certain members of management received cash distributions of $768,000.

The Partnership's contract compression segment provides contract compression services to HPC. Under a Master Services Agreement with HPC, the Partnership operates and provides all employees and services for the operation and management of HPC. Under this agreement the Partnership will receive $500,000 monthly as a partial reimbursement of its general and administrative costs. The amount is recorded as fee revenue in the Partnership's corporate and other segment. Additionally, the Partnership incurs expenditures on behalf of HPC and these amounts are billed to HPC on a monthly basis. As of and for the three and six months ended June 30, 2009, the Partnership's related party receivables, related party payables, related party revenues and related party cost of sales were primarily a result of the transactions described above.

9. Segment Information
With the completion of the Contribution Agreement, the Partnership's management realigned the composition of its segments. Accordingly, the Partnership has restated the items of segment information for earlier periods to reflect this new alignment.

The Partnership has three principal reportable segments: (a) gathering and processing, (b) transportation, and (c) 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 from the gathering and processing segment 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 Partnership, through its producer services function, primarily purchases natural gas from producers at gathering systems and plants connected to its pipeline systems and sells this gas at downstream outlets.

Following the contribution of RIGS to HPC, the transportation segment consists exclusively of the Partnership's 38 percent interest in HPC, for which equity method accounting applies. Prior periods have been restated to reflect the Partnership's then wholly owned subsidiary of Regency Intrastate Gas LLC as the exclusive reporting unit within this segment. The transportation segment uses pipelines to transport natural gas from receipt points on its system to interconnections with other pipelines, storage facilities or end-use markets. RIGS 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 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 provides customers with turn-key natural gas compression services to maximize their natural gas and crude oil production, throughput, and cash flow. The Partnership's integrated solutions include a comprehensive assessment of a customer's natural gas contract compression needs and the design and installation of a compression system that addresses those particular needs. The Partnership is responsible for the installation and ongoing operation, service, and repair of its compression units, which are modified as necessary to adapt to customers' changing operating conditions. 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.

The corporate and others segment comprises regulated entities and the Partnership's corporate offices. Revenues in this segment include the collection of the partial reimbursement of general and administrative costs from HPC.

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 consist of compressor repairs. Management believes segment margin is an important measure because it directly relates to volume, commodity price changes and revenue generating horsepower. 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 income statement period, together with amounts related to balance sheets for each segment are shown below.

	Gathering and Processing	Transportation	Contract Compression	Corporate and Others	Eliminations	Total
			(in thousands)			
External Revenue						
For the three months ended June 30, 2009	$209,939	$ 1,531	$ 39,011	$3,061	$ -	$253,542
For the three months ended June 30, 2008	503,466	9,975	32,587	677	-	546,705
For the six months ended June 30, 2009	453,093	9,075	77,499	3,853	-	543,520
For the six months ended June 30, 2008	872,535	20,209	57,854	1,342	-	951,940
Intersegment Revenue						
For the three months ended June 30, 2009	(6,745)	(128)	975	40	5,858	-
For the three months ended June 30, 2008	11,353	2,996	164	87	(14,600)	-
For the six months ended June 30, 2009	(8,755)	4,936	1,785	144	1,890	-
For the six months ended June 30, 2008	15,546	6,360	282	178	(22,366)	-
Cost of Sales						
For the three months ended June 30, 2009	144,816	1,243	4,186	269	6,833	157,347
For the three months ended June 30, 2008	466,275	(8,013)	2,907	-	(14,482)	446,687
For the six months ended June 30, 2009	327,284	2,297	6,504	116	3,674	339,875
For the six months ended June 30, 2008	784,845	(7,668)	5,272	-	(22,173)	760,276
Segment Margin						
For the three months ended June 30, 2009	58,378	160	35,800	2,832	(975)	96,195
For the three months ended June 30, 2008	48,544	20,984	29,844	764	(118)	100,018
For the six months ended June 30, 2009	117,054	11,714	72,780	3,881	(1,784)	203,645
For the six months ended June 30, 2008	103,236	34,237	52,864	1,520	(193)	191,664
Operation and Maintenance						
For the three months ended June 30, 2009	22,044	(174)	11,487	(181)	(1,202)	31,974
For the three months ended June 30, 2008	19,423	1,450	11,389	399	(145)	32,516
For the six months ended June 30, 2009	44,349	2,112	24,028	132	(2,605)	68,016

For the six months ended June 30, 2008	38,067	2,840	20,234	388	(168)	61,361
Depreciation and Amortization						
For the three months ended June 30, 2009	16,413	-	8,955	868	-	26,236
For the three months ended June 30, 2008	14,998	3,469	7,479	530	-	26,476
For the six months ended June 30, 2009	33,134	2,448	16,982	1,561	-	54,125
For the six months ended June 30, 2008	27,420	6,933	12,833	1,030	-	48,216
Assets						
June 30, 2009	1,019,842	403,565	923,684	130,193	-	2,477,284
December 31, 2008	1,103,770	325,310	881,552	148,007	-	2,458,639
Investment in Unconsolidated Subsidiary						
June 30, 2009	-	400,023	-	-	-	400,023
December 31, 2008	-	-	-	-	-	-
Goodwill						
June 30, 2009	63,232	-	164,882	-	-	228,114
December 31, 2008	63,232	34,244	164,882	-	-	262,358
Expenditures for Long-Lived Assets						
For the six months ended June 30, 2009	44,639	22,367	50,959	1,220	-	119,185
For the six months ended June 30, 2008	79,219	499	68,230	940	-	148,888

The table below provides a reconciliation of net income attributable to Regency Energy Partners LP to total segment margin.

	Three Months Ended		Six Months Ended	
	June 30, 2009	June 30, 2008	June 30, 2009	June 30, 2008
	(in thousands)			
Net income attributable to Regency Energy Partners LP	$5,890	$9,972	$154,279	$20,320
Add (deduct):				
Operation and maintenance	31,974	32,516	68,016	61,361
General and administrative	14,127	13,925	29,205	24,809
Loss (gain) on asset sales, net	651	442	(133,280)	468
Management services termination fee	-	-	-	3,888
Transaction expenses	-	147	-	534
Depreciation and amortization	26,236	26,476	54,125	48,216
Income from unconsolidated subsidiary	(1,587)	-	(1,923)	-
Interest expense, net	19,568	16,782	33,795	32,188
Other income and deductions, net	(214)	(132)	(256)	(332)
Income tax (benefit) expense	(515)	(41)	(416)	209
Net income (loss) attributable to the noncontrolling interest	65	(69)	100	3
Total segment margin	$ 96,195	$100,018	$ 203,645	$191,664

10. Equity-Based Compensation
Non-Vested Units
In December 2005, the General Partner approved a LTIP for the Partnership's employees, directors, and consultants covering an aggregate of 2,865,584 common units and providing for the awards of non-vested units and options to purchase common units. Non-vested units generally vest on the basis of one-fourth of the award each year. The Partnership expects to recognize $12,370,000 of compensation expense related to non-vested units over a weighted average period of approximately 2.41 years. All outstanding options are vested and expire ten years after the grant date. In addition, non-vested units receive the same distributions as common units.

Non-vested common units are subject to contractual restrictions against transfer which lapse over time; non-vested 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.

The non-vested common units and common unit options activity for the six months ended June 30, 2009 is as follows.

Non-Vested Common Units	Units	Weighted Average Grant Date Fair Value
Outstanding at beginning of period	704,050	$29.26
Granted	24,500	11.13
Vested	(153,291)	30.13
Forfeited or expired	(69,625)	27.88
Outstanding at end of period	505,634	28.31

Common Unit Options	Units	Weighted Average Exercise Price	Weighted Average Contractual Term (Years)	Aggregate Intrinsic Value* (in thousands)
Outstanding at beginning of period	431,918	$21.31		
Granted	-	-		
Exercised	-	-		
Forfeited or expired	(118,300)	20.92		
Outstanding at end of period	313,618	21.47	6.80	-
Exercisable at end of period	313,618	$21.47		-

* 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 the period presented. Unit options with an exercise price greater than the end of the period closing market price are excluded.

Phantom Units

During the three months ended June 30, 2009, the Partnership awarded 257,200 phantom units to senior management and certain key employees. These phantom units are in substance two grants composed of (1) service condition grants with graded vesting occurring on March 15 of each of the following three years; and (2) market condition grants with cliff vesting based upon the Partnership’s relative ranking in total unitholder return among 20 peer companies, as disclosed in Item 11 of the Partnership’s Annual Report on Form 10-K for the year ended December 31, 2008. At the end of the measurement period (March 15, 2012) for the market condition grants, the phantom units will convert to common units in a ratio ranging from 0 to 150 percent. For both the service condition grants and the market condition grants, distributions will be accumulated and paid upon vesting.

In determining the grant date fair value, the grant date closing price of the Partnership’s common units was used for the service condition awards. For the market condition awards, a Monte Carlo simulation was performed which incorporated variables such as unit price volatility, merger and acquisition activity within the peer group, changes in credit ratings of the peer group members, and employee turnover. The grant-date closing price of the Partnership’s common units was also a factor in determining the grant-date fair value of the market condition awards.

The Partnership expects to recognize $1,708,000 of compensation expense related to non-vested phantom units over a period of two years and ten months. During the three months ended June 30, 2009 the Partnership recognized $61,000 of expense, which is reflected in general and administrative expense on the condensed consolidated income statement.

The following table presents phantom unit activity for the six months ended June 30, 2009.

Phantom Units	Units	Weighted Average Grant-Date Fair Value
Outstanding at beginning of period	-	$-
Service condition grants	105,880	12.49
Market condition grants	151,320	4.49
Vested service condition	-	-
Vested market condition	-	-
Forfeited service condition	-	-
Forfeited market condition	-	-
Total outstanding at end of period	257,200	$ 7.78

11. Fair Value Measures

On January 1, 2008, the Partnership adopted the provisions of SFAS 157 for financial assets and liabilities. On January 1, 2009, the Partnership applied the provisions of SFAS 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 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 the Partnership;
- Level 2- inputs that are observable in the marketplace other than those classified as Level 1; and
- Level 3- inputs that are unobservable in the marketplace and significant to the valuation.

SFAS 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, 2009 valued based on inputs classified as Level 3 in the hierarchy.

The estimated fair value of financial instruments was determined using available market information and valuation methodologies. The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to their short-term maturities. Restricted cash and related escrow payable approximates fair value due to the relatively short-term settlement period of the escrow payable. Risk management assets and liabilities are carried at fair value. Long-term debt other than the senior notes is comprised of borrowings under which, accrues interest under a floating interest rate structure. Accordingly, the carrying value approximates fair value for the long-term debt amounts outstanding. The estimated fair value of the 8.375 and 9.375 percent senior notes based on third party market value quotations was $343,200,000 and $242,500,000, respectively, as of June 30, 2009.

12. Subsequent Event

On July 28, 2009, the Partnership declared a distribution of $0.445 per outstanding common unit including units equivalent to the General Partner’s two percent interest in the Partnership, and an aggregate distribution of approximately $643,000, with respect to incentive distribution rights, payable on August 14, 2009 to unitholders of record at the close of business on August 7, 2009.

The Partnership evaluated subsequent events up to and including August 10, 2009, the date on which these financial statements were issued.

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 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.
Joint Venture Formation. On March 17, 2009, we announced the completion of the transactions included in the Contribution Agreement relating to a new joint venture among Regency HIG, EFS Haynesville, LLC, a 100 percent owned subsidiary of GECC, and the Alinda Investors. We contributed RIGS, which owns the Regency Intrastate Gas System, valued at $400,000,000, to HPC, in exchange for a 38 percent general partnership interest in HPC. EFS Haynesville, LLC and the Alinda Investors contributed $126,500,000 and $526,500,000 in cash, respectively, to HPC in return for a 12 percent and a 50 percent general partnership interest, respectively.

HPC was formed to finance the construction and development of the Partnership's previously announced expansion of its existing natural gas pipeline in north Louisiana and to operate the Regency Intrastate Gas System.

Drilling and Pricing Pressure Trends.

General. We continue to see a decline in drilling activity in certain operating regions. As long as oil and gas prices remain at current levels, we believe that drilling activity will continue to remain low and may decline further. We believe that current drilling levels are not sufficient to meet expected demand over the next few years and that higher prices will be needed for drilling levels to rise to more normal historical levels. Management cannot predict the timing of higher natural gas prices, but if prices remain at current levels for an extended period of time, our business operations could be adversely impacted.

Contract Compression Segment. As a result of depressed natural gas prices, decreased drilling activity, and overall deteriorating economic conditions, our natural gas contract compression segment is currently experiencing a challenging environment. Overall applied horsepower decreased by 3 percent for the three months ended June 30, 2009, compared to levels as of March 31, 2009, and we anticipate continued challenges in redeploying compression that comes up for renewal as well as deploying new compression units during the near term.

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 own a 38 percent interest in HPC that delivers natural gas from northwest Louisiana to more favorable markets in northeast Louisiana through a 320-mile 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 operation 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:

- the level of workovers or recompletions of existing connected wells and successful drilling activity in areas currently dedicated to our pipelines,
- our ability to compete for volumes from successful new wells in other areas, and
- 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 gathering systems, 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 our 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. In addition, we 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.

Prior to our contribution of our Regency Intrastate Gas System to HPC, we calculated our transportation segment margin as revenue generated by fee income as well as, in those instances in which we purchase and sell gas for our account, gas sales revenue minus the cost of natural gas that we purchase and transport. Revenue primarily includes fees for the transportation of pipeline-quality natural gas and the margin generated by sales of natural gas transported for our account. Most of our segment margin is fee-based with little or no commodity price risk.

After our contribution of RIGS to HPC, we do not record segment margin for the transportation segment because the income attributable to HPC is recorded as income from unconsolidated subsidiary. Because of the materiality of HPC to the Partnership, we are providing a discussion of HPC’s results of operations and cash distributions.

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, corporate and other 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 measures of segment margin and total segment margin to their most directly comparable GAAP measure, net income, is included in Note 9, Segment Information, within the condensed consolidated financial statements included in Item 1 of this report.

Operation and Maintenance Expenses. 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 expenses from total revenues in calculating segment margin because we separately evaluate commodity volume and price changes in segment margin.

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

- financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make cash distributions to our unitholders and general 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 income and net cash flows provided by operating activities.

	Six Months Ended	
	June 30, 2009	June 30, 2008
	(in thousands)	
Net cash flows provided by operating activities	$69,271	$86,934
Add (deduct):		
Depreciation and amortization, including debt issuance cost amortization	(56,750)	(49,598)
Income from unconsolidated subsidiary	23	-
Risk management portfolio valuation changes	6,293	(20,582)
Gain (loss) on asset sales, net	133,280	(468)
Unit based compensation expenses	(2,750)	(1,839)
Changes in current assets and liabilities:		
Trade accounts receivables and accrued revenues	(38,073)	72,784
Other current assets	(3,728)	2,914
Trade accounts payable, accrued cost of gas and liquids, and related party payables	38,809	(53,088)
Other current liabilities	7,396	(15,314)
Other assets and liablities	608	(1,420)
Net income	$154,379	$20,323

Add (deduct):		
Interest expense, net	33,795	32,188
Depreciation and amortization	54,125	48,216
Income tax (benefit) expense	(416)	209
EBITDA	$241,883	$100,936

CASH DISTRIBUTIONS. On July 28, 2009, the Partnership declared a distribution of $0.445 per outstanding common unit including units equivalent to the General Partner's two percent interest in the Partnership, and an aggregate distribution of approximately $643,000, with respect to incentive distribution rights, payable on August 14, 2009 to unitholders of record at the close of business on August 7, 2009.

RESULTS OF OPERATIONS
Partnership
Three Months Ended June 30, 2009 vs. Three Months Ended June 30, 2008

	Three Months Ended			
	June 30, 2009	June 30, 2008	Change	Percent
	(in thousands except percentages and volume data)			
Revenues	$253,542	$546,705	$(293,163)	54 %
Cost of sales	157,347	446,687	(289,340)	65
Total segment margin (1)	96,195	100,018	(3,823)	4
Operation and maintenance	31,974	32,516	(542)	2
General and administrative	14,127	13,925	202	1
Loss on asset sales, net	651	442	209	47
Transaction expense	-	147	(147)	N/M
Depreciation and amortization	26,236	26,476	(240)	1
Operating income	23,207	26,512	(3,305)	12
Income from unconsolidated subsidiary	1,587	-	1,587	N/M
Interest expense, net	(19,568)	(16,782)	(2,786)	17
Other income and deductions, net	214	132	82	62
Income tax benefit	(515)	(41)	(474)	1,156
Net (income) loss attributable to the noncontrolling interest	(65)	69	(134)	194
Net income attributable to Regency Energy Partners LP	$5,890	$9,972	$(4,082)	41 %
System inlet volumes (MMbtu/d) (2)	1,527,501	1,519,790	7,711	1
Revenue generating horsepower (3)	767,060	669,804	97,256	15

(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 9, Segment Information."
(2) System inlet volumes include total volumes taken into both our gathering and processing and transportation systems.
(3) Revenue generating horsepower is our total available horsepower less horsepower under contract that is not generating revenue and idle horsepower.
N/M – not meaningful

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

	Three Months Ended June 30, 2009	June 30, 2008	Change	Percent
	(in thousands except percentage and volume data)			
Segment Financial and Operating Data:				
Gathering and Processing Segment				
Financial data:				
Segment margin (1) (2) (3)	$58,378	$48,544	$9,834	20 %
Operation and maintenance (4)	22,044	19,423	2,621	13
Operating data:				
Throughput (MMbtu/d) (5)	984,718	995,922	(11,204)	-
NGL gross production (Bbls/d)	22,024	22,526	(502)	2
Transportation Segment				
Financial data:				
Segment margin (1) (2) (3)	$160	$20,984	$(20,824)	99
Operation and maintenance (4)	(174)	1,450	(1,624)	112
Operating data:				
Throughput (MMbtu/d) (5)	-	793,339	(793,339)	100
Contract Compression Segment				
Financial data:				
Segment margin (1) (3)	$35,800	$29,844	$5,956	20
Operation and maintenance (4)	11,487	11,389	98	1
Operating data:				
Revenue generating horsepower (6)	767,060	669,804	97,256	15
Average horsepower per revenue generating compression unit	846	849	(3)	-
Corporate &Others				
Financial data:				
Segment margin (1) (2) (3)	$2,832	$764	$2,068	271
Operation and maintenance (4)	(181)	399	(580)	145

(1) For a reconciliation of segment margin to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read "Item 1. Financial Statements-Note 9, Segment Information." 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) Segment margins differ from previously disclosed amounts due to functional reorganization of our operating segments.
(3) Combined segment margin varies from consolidated segment margin due to intersegment eliminations.
(4) Combined operation and maintenance expense varies from consolidated operation and maintenance expense due to intersegment eliminations.
(5) Combined throughput volumes for the gathering and processing and transportation segments vary from consolidated system inlet volumes due to inter-segment eliminations.

(6) Revenue generating horsepower is our total available horsepower less horsepower under contract that is not generating revenue and idle horsepower.

In addition to the revenue generating horsepower and units owned and operated by the contract compression segment disclosed below, the contract compression segment operates 163,507 horsepower owned by the gathering and processing and transportation segments as of June 30, 2009. The contract compression also operates 15,560 horsepower owned by HPC as of June 30, 2009.

	June 30, 2009		
Horsepower Range	Revenue Generating Horsepower	Percentage of Revenue Generating Horsepower	Number of Units
0-499	64,648	8 %	363
500-999	82,397	11 %	133
1,000+	620,015	81 %	411
	767,060	100 %	907

	March 31, 2009		
Horsepower Range	Revenue Generating Horsepower	Percentage of Revenue Generating Horsepower	Number of Units
0-499	62,147	8 %	360
500-999	80,587	10 %	129
1,000+	646,760	82 %	431
	789,494	100 %	920

Net Income Attributable to the Partnership. Net income attributable to the Partnership for the three months ended June 30, 2009 was $5,890,000 compared to $9,972,000 in the three months ended June 30, 2008, a 41 percent decrease. The decrease in net income was primarily due to a decrease in total segment margin of $3,823,000 caused by lower commodity prices in the gathering and processing segment from the same period in 2008, and an increase of interest expense of $2,786,000 primarily associated with the issuance of $250,000,000 senior notes in May 2009 as well as the higher interest rates. This decrease was partially offset by:

- $1,587,000 of income from HPC, which was established in March 2009; and
- a decrease in operation and maintenance expense of $542,000, primarily due to cost controls and efficiency measures.

Segment Margin. Total segment margin for the three months ended June 30, 2009 decreased by $3,823,000 compared with the three months ended June 30, 2008. This decrease was the net result of a $20,824,000 decrease in transportation segment margin attributable to our contribution of RIGS to HPC on March 17, 2009, offset by an increase of $9,834,000 in the gathering and processing segment and an increase of $5,956,000 in the contract compression segment margin. Combined segment margin varies from consolidated segment margin by $975,000 and $118,000 in the three months ended June 30, 2009 and 2008, respectively, due to intersegment eliminations between our reporting segments. Segment margins differ from previously disclosed amounts due to the functional reorganization of our operating segments.

Gathering and processing segment margin increased to $58,378,000 in the three months ended June 30, 2009 from $48,544,000 for the three months ended June 30, 2008. The major component of this increase was $20,213,000 from non-cash changes in the value of certain risk management contracts related to our hedging programs. This increase was partially offset by:

- $10,009,000 related to lower commodity prices compared to 2008 price levels; and
- $370,000 net decrease from various other sources.

Transportation segment margin decreased to $160,000 for the three months ended June 30, 2009 from $20,984,000 for the three months ended June 30, 2008. This decrease primarily relates to the contribution of RIGS to HPC on March 17, 2009.

Contract compression segment margin increased to $35,800,000 in the three months ended June 30, 2009 from $29,844,000 for the three months ended months ended June 30, 2008. The increase in contract compression segment margin is primarily attributable to a 97,256 increase in revenue generating horsepower.

Operation and Maintenance. Operation and maintenance expense decreased to $31,974,000 in the three months ended June 30, 2009 from $32,516,000 for the corresponding period in 2008, a two percent decrease. This net decrease in operation and maintenance expense was the result of the following factors:

- $654,000 decrease in property tax due to the contribution of our RIGS assets to HPC; and offset by
- $112,000 net increase in various other operation and maintenance expenses.

General and Administrative. General and administrative expense increased to $14,127,000 in the three months ended June 30, 2009 from $13,925,000 for the same period in 2008, a one percent increase. This increase is the net effect of:

- $951,000 increase primarily in professional services, telecommunication, rent and investor related expenses; and offset by
- $749,000 decrease in various other general and administrative expenses.

Depreciation and Amortization. Depreciation and amortization expense decreased to $26,236,000 in the three months ended June 30, 2009 from $26,476,000 for the three months ended June 30, 2008, a one percent decrease. The net decrease in depreciation expense is attributed to the following factors:

- $3,469,000 decrease in depreciation and amortization expense related to the contribution of RIGS to HPC, and was partially offset by
- $1,754,000 related to various organic growth projects primarily in the gathering and processing segment completed since June 30, 2008; and
- $1,475,000 increase in the contract compression segment due to compression placed in service since June 30, 2008;

Interest Expense, Net. Interest expense, net increased by $2,786,000, or 17 percent, in the three months ended June 30, 2009 compared to the same period in 2008. Interest expense, net increased by $1,603,000 due to higher interest rates and $1,183,000 primarily due to increased levels of borrowing.

Six Months Ended June 30, 2009 vs. Six Months Ended June 30, 2008

	Six Months Ended June 30, 2009	June 30, 2008	Change	Percent
	(in thousands except percentages and volume data)			
Revenues	$543,520	$951,940	$(408,420)	43 %
Cost of sales	339,875	760,276	(420,401)	55
Total segment margin (1)	203,645	191,664	11,981	6
Operation and maintenance	68,016	61,361	6,655	11
General and administrative	29,205	24,809	4,396	18
Loss (gain) on asset sales, net	(133,280)	468	(133,748)	N/M
Management services termination fee	-	3,888	(3,888)	N/M
Transaction expense	-	534	(534)	N/M
Depreciation and amortization	54,125	48,216	5,909	12
Operating income	185,579	52,388	133,191	254
Income from unconsolidated subsidiary	1,923	-	1,923	N/M
Interest expense, net	(33,795)	(32,188)	(1,607)	5
Other income and deductions, net	256	332	(76)	23
Income tax expense (benefit)	(416)	209	(625)	299
Net income attributable to the noncontrolling interest	(100)	(3)	(97)	3,233
Net income attributable to Regency Energy Partners LP	$154,279	$20,320	$133,959	659 %
System inlet volumes (MMbtu/d) (2)	1,572,670	1,448,173	124,497	9
Revenue generating horsepower (3)	767,060	669,804	97,256	15

(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 9, Segment Information.”
(2) System inlet volumes include total volumes taken into both our gathering and processing and transportation systems.
(3) Revenue generating horsepower is our total available horsepower less horsepower under contract that is not generating revenue and idle horsepower.
N/M – not meaningful

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

	Six Months Ended June 30, 2009	June 30, 2008	Change		Percent	
	(in thousands except percentage and volume data)					
Segment Financial and Operating Data:						
Gathering and Processing Segment						
Financial data:						
Segment margin (1) (2) (3)	$117,054	$103,236	$13,818		13	%
Operation and maintenance (4)	44,349	38,067	6,282		17	
Operating data:						
Throughput (MMbtu/d) (5)	1,011,563	956,248	55,315		6	
NGL gross production (Bbls/d)	21,903	22,796	(893	)	4	
Transportation Segment						
Financial data:						
Segment margin (1) (2) (3)	$11,714	$34,237	$(22,523	)	66	
Operation and maintenance (4)	2,112	2,840	(728	)	26	
Operating data:						
Throughput (MMbtu/d) (5)	777,832	762,673	15,159		2	
Contract Compression Segment						
Financial data:						
Segment margin (1) (3)	$72,780	$52,864	$19,916		38	
Operation and maintenance (4)	24,028	20,234	3,794		19	
Operating data:						
Revenue generating horsepower (6)	767,060	669,804	97,256		15	
Average horsepower per revenue generating compression unit	846	849	(3	)	-	
Corporate &Others						
Financial data:						
Segment margin (1) (2) (3)	$3,881	$1,520	$2,361		155	
Operation and maintenance (4)	132	388	(256	)	66	

(1) For a reconciliation of segment margin to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read "Item 1. Financial Statements-Note 9, Segment Information." 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) Segment margins differ from previously disclosed amounts due to functional reorganization of our operating segments.
(3) Combined segment margin varies from consolidated segment margin due to intersegment eliminations.
(4) Combined operation and maintenance expense varies from consolidated operation and maintenance expense due to intersegment eliminations.
(5) Combined throughput volumes for the gathering and processing and transportation segments vary from consolidated system inlet volumes due to inter-segment eliminations.

(6) Revenue generating horsepower is our total available horsepower less horsepower under contract that is not generating revenue and idle horsepower.

Net Income Attributable to the Partnership. Net income attributable to the Partnership for the six months ended June 30, 2009 was $154,279,000 compared to $20,320,000 in the six months ended June 30, 2008, a 659 percent increase. The increase in net income attributable to the Partnership was primarily due to the recording of a $133,451,000 gain primarily associated with the RIGS assets which we contributed to HPC and an increase in total segment margin of $11,981,000 discussed below. Also contributing to the increase was the absence in 2009 of $3,888,000 of a management services termination fee related to the acquisition of our FrontStreet assets in 2008. This increase was partially offset by:

- an increase in operation and maintenance expense of $6,655,000 primarily due to increase emphasis on the maintenance of our gathering and processing compression fleet; and
- an increase in depreciation and amortization expense of $5,909,000 related primarily to organic growth projects in the gathering and processing segment primarily in south and west Texas as well as the contract compression segment;
- an increase in general and administrative expense of $4,396,000 primarily due to increases in employee-related expenses and various other general and administrative expenses.

Segment Margin. Total segment margin for the six months ended June 30, 2009 increased $11,981,000 compared with the six months ended June 30, 2008. This increase was attributable to an increase of $13,818,000 in the gathering and processing segment, an increase of $19,916,000 in the contract compression segment margin, partially offset by a $22,523,000 decrease in transportation segment margin. Combined segment margin varies from consolidated segment margin by $1,784,000 and $193,000 for the six months ended June 30, 2009 and 2008, respectively, due to intersegment eliminations between our reporting segments. Segment margins differ from previously disclosed amounts due to the functional reorganization of our operating segments.

Gathering and processing segment margin increased to $117,054,000 in the six months ended June 30, 2009 from $103,236,000 for the six months ended June 30, 2008. The major components of this increase were as follows:

- $26,867,000 from non-cash changes in the value of certain risk management contracts related to our hedging programs;
- $6,045,000 related to our producer services function; and were partially offset by
- $15,529,000 related to lower commodity prices compared to 2008 price levels; and
- $3,565,000 decrease from various other sources.

Transportation segment margin decreased to $11,714,000 for the six months ended June 30, 2009 from $34,237,000 for the six months ended June 30, 2008 primarily due to the contribution of RIGS to HPC on March 17, 2009.

Contract compression segment margin increased to $72,780,000 in the six months ended June 30, 2009 from $52,864,000 for the six months ended months ended June 30, 2008. The increase is primarily attributable to a 97,256 increase in revenue generating horsepower, a 15 percent increase, enhanced by the exclusion of 15 days in 2008 of activity due to the timing of the CDM acquisition. This 15-day period also impacts other contract compression segment explanations below.

Operation and Maintenance. Operation and maintenance expense increased to $68,016,000 in the six months ended June 30, 2009 from $61,361,000 for the corresponding period in 2008, an 11 percent increase. This increase was the result of the following factors:

- $5,730,000 increase in compression operation and maintenance expense primarily in the gathering and processing segment due to the increased focus on maintenance of our compression fleet; and
- $925,000 increase in various other operation and maintenance expenses.

General and Administrative. General and administrative expense increased to $29,205,000 in the six months ended June 30, 2009 from $24,809,000 for the same period in 2008, an 18 percent increase. This increase was due to:

- $1,679,000 increase in employee-related expenses due to increased employer benefit payments and bonus accrual;
- $1,353,000 increase in telecommunication, investor relations, and various other general and administrative expenses;
- $866,000 increase in professional and consulting service primarily due to legal fees and fees paid for Sarbanes Oxley compliance in the contract compression segment; and
- $498,000 increase in rent expense primarily due to the new office lease for corporate headquarters.

Gain on Asset Sales, Net. Gain on asset sales, net primarily comprised of $133,451,000 gain in the six months ended June 30, 2009 associated with assets contributed to HPC (of which $52,813,000 represents the remeasurement of the Partnership retained 38 percent interest to its fair value), net of transaction costs of $5,530,000.

Depreciation and Amortization. Depreciation and amortization expense increased to $54,125,000 in the six months ended June 30, 2009 from $48,216,000 for the six months ended June 30, 2008, a 12 percent increase. The following factors contributed to this increase:

- $5,097,000 related to various organic growth projects completed since June 30, 2008 primarily in the gathering and processing segment in south and west Texas;
- $4,149,000 related to our contract compression assets;
- $1,148,000 related to our Nexus assets acquired on March 25, 2008; and were partially offset by a
- $4,485,000 decrease in depreciation expense related to the contribution of RIGS to HPC.

Interest Expense, Net. Interest expense, net increased by $1,607,000, or 5 percent, in the six months ended June 30, 2009 compared to the same period in 2008. Interest expense, net increased by $4,033,000 due to increased levels of borrowings and was partially offset by a decrease of $2,426,000 primarily due to lower interest rates.

HPC

Three Months Ended June 30, 2009 vs. Three Months Ended June 30, 2008

We own a 38 percent interest in HPC and the following management discussion and analysis is for 100 percent of HPC's results of operations. For comparative purposes only, we have presented HPC's results of operations for the three months ended June 30, 2009 with the results of RIGS for the three months ended June 30, 2008. The following table contains key performance indicators related to our discussion of the results of operations.

	Three Months Ended			
	June 30, 2009	June 30, 2008	Change	Percent
	(in thousands except percentages and volume data)			
Revenues	$12,625	$12,861	$(236)	2 %
Cost of sales	(178)	(8,123)	7,945	98
HPC margin (1)	12,803	20,984	(8,181)	39
Operation and maintenance	2,670	1,450	1,220	84
General and administrative	1,675	1	1,674	N/M
Loss on sale of asset, net	129	-	129	N/M
Depreciation and amortization	4,443	3,469	974	28
Operating income	3,886	16,064	(12,178)	76
Other income and deductions, net	509	-	509	N/M
Net income	$4,395	$16,064	$(11,669)	73 %
System inlet volumes (MMbtu/d)	745,178	793,339	(48,161)	6

N/M – not meaningful

(1) The following provides a reconciliation of HPC margin to net income.

	Three Months Ended	
	June 30, 2009	June 30, 2008
Net income	$4,395	$16,064
Add (deduct):		
Operation and maintenance	2,670	1,450
General and administrative	1,675	1
Loss on sale of asset, net	129	-
Depreciation and amortization	4,443	3,469
Other income and deductions, net	(509)	-
Total HPC margin	$12,803	$20,984

Results of Operations Discussion. Net income for the three months ended June 30, 2009 was $4,395,000 compared to $16,064,000 in the three months ended June 30, 2008, a 73 percent decrease. The decrease in net income was primarily attributable to the following:

- a decrease in HPC margin of $8,181,000 primarily due to the decrease in natural gas prices in the three month ended June 30, 2009 compared to the same period in 2008;
- an increase in operation and maintenance expense of $1,220,000 mainly resulting from increased contractor expense related to compression operations; and
- an increase in general and administrative expense of $1,674,000 primarily due to the recording of a management fee paid to the Partnership.

Six Months Ended June 30, 2009 vs. Six Months Ended June 30, 2008

We own a 38 percent interest in HPC and the following management discussion and analysis is for 100 percent of HPC's results of operations. For comparative purposes only, we have combined the results of operations of RIGS from January 1, 2009 to March 17, 2009, with the results of operations of HPC from inception (March 18, 2009) to June 30, 2009 to compare to RIGS' results of operations for the six months ended June 30, 2008. The following table contains key performance indicators related to our discussion of the results of operations.

	Six Months Ended			
	June 30, 2009	June 30, 2008	Change	Percent
	(in thousands except percentages and volume data)			
Revenues	$26,780	$26,354	$426	2 %
Cost of sales	421	(7,883)	8,304	105
HPC margin (1)	26,359	34,237	(7,878)	23
Operation and maintenance	5,281	2,840	2,441	86
General and administrative	1,923	-	1,923	N/M
Loss on sale of asset, net	129	44	85	193
Depreciation and amortization	7,560	6,933	627	9
Operating income	11,466	24,420	(12,954)	53
Other income and deductions, net	613	-	613	N/M
Net income	$12,079	$24,420	$(12,341)	51 %
System inlet volumes (MMbtu/d)	777,832	762,673	15,159	2

N/M – not meaningful

(1) The following provides a reconciliation of HPC margin to net income.

	Six Months Ended	
	June 30, 2009	June 30, 2008
Net income	$12,079	$24,420
Add (deduct):		
Operation and maintenance	5,281	2,840
General and administrative	1,923	-
Loss on sale of asset, net	129	44
Depreciation and amortization	7,560	6,933
Other income and deductions, net	(613)	-
Total HPC margin	$26,359	$34,237

Results of Operations Discussion. Net income for the six months ended June 30, 2009 was $12,079,000 compared to $24,420,000 in the six months ended June 30, 2008, a 51 percent decrease. The decrease in net income was primarily attributable to the following:

- a decrease in HPC margin of $7,878,000 due primarily to the decrease in natural gas prices in 2009 compared to 2008;
- an increase in operation and maintenance expense of $2,441,000 mainly resulting from increased contractor expense related to compression operations; and
- an increase in general and administrative expense of $1,923,000 primarily due to the recording of a management fee paid to the Partnership.

HPC's EBITDA for the three and six months ended June 30, 2009 and 2008 is presented below.

	Three Months Ended		Six Months Ended	
	June 30, 2009	June 30, 2008	June 30, 2009	June 30, 2008
	(in thousands)			
Net income	$4,395	$16,064	$12,079	$24,420
Add: Depreciation and amortization	4,443	3,469	7,560	6,933
EBITDA	$8,838	$19,533	$19,639	$31,353

Cash Distributions. On July 22, 2009, the HPC management committee declared a distribution of $8,651,000, which was paid on July 30, 2009, of which the Partnership received its pro-rata share of $3,287,000.

On July 27, 2009, HPC entered into a $25,000,000 revolving credit facility that expires on July 27, 2012 secured by substantially all of its assets.

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, 2008.

Equity Method Investments. The equity method of accounting is used to account for the Partnership's interest in investments greater than 20 percent voting stock of an investee and where the Partnership lacks control over the investee.

See Item 1, Note 1-Organization and Summary of Significant Accounting Policies of this Form 10-Q for the description of recently issued accounting standards.

OTHER MATTERS

Information regarding the Partnership's commitments and contingencies are included in Note 7-Commitments and Contingencies to the condensed consolidated financial statements included in Item 1 of this report.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

We expect our sources of liquidity to include:

- cash generated from operations;
- borrowings under our credit facility;
- distributions received from HPC;
- operating lease facilities;
- debt offerings; and
- issuance of additional partnership units.

We have experienced, and expect to continue to experience, substantial capital expenditure and working capital needs. At June 30, 2009, the Partnership has purchase obligations totaling approximately $17,414,000 for the purchase of major compression components that extend until the year ending December 31, 2009.

In the future, HPC may request that we make additional capital contributions to support the joint venture's capital expenditures. If such capital contributions are required, we may not be able to obtain the financing necessary to satisfy our obligations. In addition, we have agreed to reimburse the joint venture for the first $20,000,000 of any cost overruns which might occur relating to the Haynesville expansion project currently being constructed by HPC (Haynesville Expansion Project).

Global financial markets and economic conditions have been, and continue to be, disrupted and volatile. The cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets generally has diminished significantly. Although debt and equity markets have recovered somewhat from the distressed condition of last fall and earlier this year, we expect that our ability to issue debt and equity at prices that are similar to offerings in recent years will be limited.

Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to our current debt and reduced and, in some cases, ceased to provide funding to borrowers. For example, as a result of Lehman filing a petition under Chapter 11 of the U.S. Bankruptcy Code, a subsidiary of Lehman that is a committed lender under our credit facility has declined requests to honor its commitment to lend under our credit facility. The total amount available to us under our credit facility as of July 31, 2009 was $285,234,000, which has been reduced by the amount of Lehman's commitment of $7,030,000 that is no longer available to us. If we repay any of the amounts we have already borrowed from Lehman, we may not be able to reborrow such amounts. We may be unable to utilize the full borrowing capacity under our credit facility if other lenders are not willing to provide additional funding to make up the portion of the credit facility commitments that Lehman's subsidiary has refused to fund or if any of the remaining committed lenders are unable or unwilling to fund their respective portion of any funding request we make under our credit facility.

We expect our growth capital expenditures to be approximately $107,000,000 in 2009 and $100,000,000 in 2010, exclusive of growth capital expenditures related to the Haynesville Expansion Project. Our anticipated 2009 organic growth capital expenditures of $107,000,000 include $82,000,000 for additional compression for our contract compression segment and $25,000,000 for the expansion of our gathering and processing facilities. We expect to utilize $25,000,000 of our $75,000,000 CDM operating lease facility with Caterpillar Financial Services to fund our contract compression capital expenditures.

Although we intend to move forward with certain planned internal growth projects, we may further revise the timing and scope of these projects as necessary to adapt to existing economic conditions, and the benefits expected to accrue to our unitholders from our expansion activities may be diminished by substantial cost of capital increases during this period. As a result of these costs, our cash flows may decrease, which could impair our liquidity position and require us to reduce our distributions to unitholders.

Finally, if there is a significant lessening in demand for our services as a result of extended declines in the actual and longer term expected price of oil and gas and gas related drilling activity, we may see a further reduction in our capital expenditures and lesser requirements for working capital, both of which could improve operating cash flow and liquidity compared to the prior period and offset reduced cash generated from operations, excluding working capital changes.

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 may 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 value changes in our derivative positions being reflected on our balance sheet. These risk management assets and liabilities 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 deferred revenues as 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 increased by $10,868,000 from December 31, 2008 to June 30, 2009, primarily due to:

- a net increase in accounts receivable and payable of $11,412,000 due primarily to the timing of cash receipts and disbursements;
- a net increase in cash and cash equivalents, restricted cash and escrow payable of $8,680,000;
- a net decrease in risk management assets and liabilities of $8,264,000 as existing contracts settled and no significant new contracts were added; and
- a net decrease in other current assets and liabilities of $960,000 primarily due to the amortization of prepaid insurance and other prepaid expense items of $3,944,000, that was mostly offset by a $2,669,000 increase in interest payable associated with our 9.375 percent senior notes.

Cash Flows from Operations. Net cash flows provided by operating activities decreased $17,663,000, or 20 percent, for the six months ended June 30, 2009 as compared to the same period in 2008, primarily due to lower commodity prices and a slight decline in volumes flowing through our systems and the timing of cash receipts and disbursements associated with receivables and payables.

Cash Flows from Investing Activities. Net cash flows used in investing activities was $36,003,000 in the six months ended June 30, 2009 compared to net cash flows used in investing activities of $725,653,000 in the six months ended June 30, 2008. The net cash flows used in investing activities in the six months ended June 30, 2008 was primarily related to the acquisition of FrontStreet, CDM and Nexus.

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.

Growth Capital Expenditures. In the six months ended June 30, 2009, we incurred $17,905,000 for various growth projects in the gathering and processing segment, which excludes growth capital expenditures related to the Haynesville Expansion Project. We also incurred $63,444,000 for the fabrication of new compression packages and ancillary assets for our contract compression segment.

Expenditures incurred by us for the Haynesville Expansion project of $80,607,000 prior to contribution of RIGS to HPC were reimbursed to us by HPC upon contribution.

Maintenance Capital Expenditures. In the six months ended June 30, 2009, we incurred $7,933,000 of maintenance capital expenditures. Maintenance capital expenditures primarily consist of compressor and equipment overhauls.

Cash Flows from Financing Activities. Net cash flows used in financing activities was $24,592,000 in the six months ended June 30, 2009 compared to net cash flows provided by financing activities of $635,733,000 in the same period in 2008. In the six months ended June 30, 2009, cash flows used in financing activities related primarily to partner distributions and repayments of revolving credit facilities, partially offset by the issuance of senior notes. In the six months ended June 30, 2008, cash flows provided by financing activities were primarily associated with borrowings for our FrontStreet, CDM and Nexus acquisitions.

Capital Resources

Credit Ratings. Our credit ratings as of June 30, 2009 are provided below.

	Moody's	Standard & Poor's
Regency Energy Partners LP		
Outlook	Negative	Negative
Senior notes 8 3/8	B1	B
Senior notes 9 3/8	B1	B
Corporate rating/total debt	Ba3	BB-

On May 20, 2009, the Partnership and Finance Corp. issued $250,000,000 senior notes in a private placement that mature on June 1, 2016. The senior notes bear interest at 9.375 percent with interest payable semiannually on June 1 and December 1. The proceeds were used to partially repay revolving loans under our credit facility.

We have a commitment to register the 9.375 percent senior notes due 2016 by May 2010. Failure to do so would result in a registration default. For the first 90 day period beyond the registration default, we would be required to pay .25 percent of the face amount of the notes as liquidated damages until the default is cured. The rate of liquidated damages would increase by an additional .25 percent for each subsequent 90 day period of the registration default, with a maximum amount of liquidated damages of 1.0 percent per year. We expect to be able to register the notes in a timely manner, and accordingly have not recognized a liability for this registration payment arrangement.

At any time before June 1, 2012, up to 35 percent of the senior notes can be redeemed at a price of 109.375 percent plus accrued interest and liquidated damages. On or after June 1, 2013, all or part of the senior notes can be redeemed at a price of 100 percent plus accrued interest and liquidated damages. At any time prior to June 1, 2013, we may also redeem all or part of the notes at a price equal to 100 percent of the principal amount of notes redeemed plus accrued interest, liquidated damages, and the applicable premium, which equals to the greater of (1) 1 percent of the principal amount of the note; or (2) the excess of the present value at such redemption date of (i) the redemption price of the note at June 1, 2013 plus (ii) all required interest payments due on the note through June 1, 2013, computed using a discount rate equal to the Treasury Rate as of such redemption date plus 50 basis points; over the principal amount of the note.

Upon change of control each note holder will be entitled to require us to purchase all or a portion of its notes at a purchase price of 101 percent plus accrued interest and liquidated damages. The senior notes contain various covenants that limit, among other things, our ability and the ability of certain of our subsidiaries to:

- incur additional indebtedness;
- pay distributions on, or repurchase or redeem equity interests;
- make certain investments;
- incur liens;
- enter into certain types of transactions with affiliates; and
- sell assets, consolidate or merge with or into other companies.

Fourth Amended and Restated Credit Agreement. RGS is a party to the Fourth Amended and Restated Credit Agreement dated as of August 15, 2006 among RGS, the Partnership, the guarantors party thereto, (as amended, the “Credit Agreement”), and on March 17, 2009, RGS amended the credit agreement.

The amendment, among other things, (a) authorizes the contribution by Regency HIG of its ownership interests in RIGS to HPC and future investments in HPC of up to $135,000,000 in the aggregate, (b) permits distributions by RGS to the Partnership in an amount equal to the outstanding loans, interest and fees under a $45,000,000 revolving credit facility with GECC entered into on February 26, 2009, (c) adds an additional financial covenant that limits the ratio of senior secured indebtedness to EBITDA, (d) provides for certain EBITDA adjustments in connection with the Haynesville Expansion Project and (e) increases the applicable margins and commitment fees applicable to the credit facility, as further described below.

The amendment provides, (a) the alternate base rate used to calculate interest on base rate loans will be calculated based on the greatest to occur of a base rate, a federal funds effective rate plus 0.50 percent and an adjusted LIBOR rate for a borrowing with a one-month interest period plus 1.50 percent, (b) the applicable margin that is used in calculating interest shall range from 1.50 percent to 2.25 percent for base rate loans and from 2.50 percent to 3.25 percent for Eurodollar loans and (c) commitment fees will range from 0.375 percent to 0.500 percent.

The amendment prohibits RGS or its subsidiaries from allowing HPC to incur or permit to exist any preferred interests or indebtedness for borrowed money of HPC prior to the completion date of the Haynesville Expansion Project. RGS and GECC have agreed with the lenders that, after the closing of the Contribution Agreement, they will not permit their representatives on the management committee of HPC to violate such restriction.

On July 24, 2009, RGS amended its credit agreement to allow for a $25,000,000 working capital facility for the RIGS Haynesville Joint Venture.

GECC Credit Facility. Upon the closing of our contribution of RIGS to HPC, the $45,000,000 GECC credit facility terminated.

HPC Working Capital Facility. On July 27, 2009, HPC entered into a $25,000,000 revolving credit facility that expires on July 27, 2012. We believe HPC's working capital facility will reduce the likelihood of us having to fund 38 percent of HPC's working capital needs in the future.

Contractual Obligations. The following table summarizes our contractual cash obligations for long-term debt and purchase obligations as of June 30, 2009.

			Payment Period		
Contractual Cash Obligations	Total	2009	2010-2011	2012-2013	Thereafter
			(in thousands)		
Long-term debt (including interest) (1)	$1,558,948	$41,083	$745,015	$464,256	$308,594
Capital leases	9,765	308	1,011	884	7,562
Operating leases	27,542	2,065	7,657	5,769	12,051
Purchase obligations	17,414	17,414	-	-	-
Total (2) (3)	$1,613,669	$60,870	$753,683	$470,909	$328,207

(1) Assumes a constant LIBOR interest rate of 1.6 percent plus the applicable margin (3.0 percent as of June 30, 2009) for our revolving credit facility. The principal of our outstanding senior notes ($357,500,000 and $250,000,000) bears a fixed interest rate of 8 3/8 percent and 9 3/8, respectively.
(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 $7,680,000 as the amount payable by period can not be reasonably estimated.

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

	As of June 30, 2009		As of July 31, 2009		
	2009	2010	2009	2010	2011
NGLs	97%	37%	97%	56%	18%
Condensate	76%	76%	76%	76%	18%
Natural gas	85%	44%	85%	44%	0%

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

The following table sets forth certain information regarding our natural gas, NGLs, West Texas Intermediate Crude ("WTI") and interest rate swaps outstanding at June 30, 2009. The relevant index price for NGLs 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). The relevant index price for natural gas that we pay is the settlement price of the natural gas as made by the NYMEX on the pricing dates as defined by the swap contracts. The relevant index price for WTI that we pay is the monthly average of the daily price of WTI as reported by the NYMEX.

Period	Underlying	Notional Volume/Amount		We Pay	We Receive		Fair Value Asset (Liablity) (in thousands)
July 2009-December 2009	Ethane	353	(MBbls)	Index	$ 0.80	($/gallon)	$ 4,928
July 2009-December 2010	Propane	484	(MBbls)	Index	$ 0.9815-$1.5325	($/gallon)	9,618
July 2009-December 2010	Iso Butane	110	(MBbls)	Index	$ 1.685-$1.915	($/gallon)	2,881
July 2009-December 2010	Normal Butane	209	(MBbls)	Index	$ 1.166-$1.895	($/gallon)	3,500
July 2009-December 2010	Natural Gasoline	209	(MBbls)	Index	$ 1.4975-$2.53	($/gallon)	5,609
July 2009-December 2010	West Texas Intermediate Crude	357	(MBbls)	Index	$ 68.17-$121.3	($/Bbl)	10,357

July 2009-December 2010	Natural gas	3,665,000	(MMBtu)	Index	$ 5.628-$6.894		($/MMBtu)	4,121
July 2009-December 2010	Interest Rate	$ 300,000,000		2.40%		One-month	LIBOR	(3,767)
Credit risk adjustment								(550)
							Total Fair Value $	36,697

In May 2009, we entered into a natural gas swap to hedge a portion of our equity exposure to natural gas for 2010. This natural gas swap was designated as a cash flow hedge.

In July 2009, we entered offsetting trades against our existing 2010 NGL portfolio of mark-to-market hedges, which we believe will substantially reduce the volatility of our 2010 NGL hedges. This group of trades, along with the pre-existing 2010 NGL portfolio, will continue to be accounted for on a mark-to-market basis. Simultaneously, we executed additional 2010 NGL swaps which were designated as cash flow hedges.

Additionally, in July 2009, we entered into swap transactions to hedge a portion of its forecasted NGLs and condensate equity exposure for the first half of 2011. These swaps are accounted for using mark-to-market accounting.

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, 2009 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 7, 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

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, 2008, which could materially affect our business, financial condition, or future results. The risks discussed in our Annual Report on Form 10-K are not the only risks facing our Partnership.

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

None.

Item 6. Exhibits

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

Exhibit 4.3 – Indenture for 9 3/8 percent Senior Notes due 2016
Exhibit 4.4 – Registration Rights Agreement for 9 3/8 percent Senior Notes due 2016
Exhibit 10.1 – Amendment to Master Lease Agreement of CDM Resource Management
Exhibit 12.1 – Computation of Ratio of Earnings to Fixed Charges
Exhibit 31.1 – Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer
Exhibit 31.2 – Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer
Exhibit 32.1 – Section 1350 Certifications of Chief Executive Officer
Exhibit 32.2 – Section 1350 Certifications of Chief Financial Officer
Exhibit 99.1 – Regency GP LP June 30, 2009 Condensed Consolidated Balance Sheet