Regency Energy Partners LP
Form 10-Q
November 09, 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 September 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 81,116,978 common units outstanding as of October 31, 2009.

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
EFS Haynesville	EFS Haynesville, LLC, a 100 percent owned subsidiary of GECC
El Paso	El Paso Field Services, LP
FASB	Financial Accounting Standards Board
FASB ASC	FASB Accounting Standards Codification
FASB ASU	FASB Accounting Standards Update
FERC	Federal Energy Regulatory Commission
Finance Corp.	Regency Energy Finance Corp., a wholly-owned subsidiary of the Partnership
FrontStreet	FrontStreet Hugoton LLC
GAAP	Accounting principles generally accepted in the United States
GE	General Electric Company
GE EFS	General Electric Energy Financial Services, a unit of GECC, combined with Regency GP Acquirer LP and Regency LP Acquirer LP
GECC	General Electric Capital Corporation, an indirect wholly owned subsidiary of GE
General Partner	Regency GP LP, the general partner of the Partnership, or Regency GP LLC, the general partner of Regency GP LP, which effectively manages the business and affairs of the Partnership through Regency Employees Management LLC
HPC	RIGS Haynesville Partnership Co., a general partnership that owns 100 percent of RIGS
IDRs	Incentive Distribution Rights
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
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)

	September 30, 2009		December 31, 2008	
ASSETS				
Current Assets:				
Cash and cash equivalents	$	12,100	$	599
Restricted cash		1,510		10,031
Trade accounts receivable, net of allowance of $1,668 and $941		25,531		40,875
Accrued revenues		65,370		96,712
Related party receivables		6,852		855
Derivative assets		33,750		73,993
Other current assets		7,381		13,338
Total current assets		152,494		236,403
Property, Plant and Equipment:				
Gathering and transmission systems		462,900		652,267
Compression equipment		808,063		799,527
Gas plants and buildings		159,389		156,246
Other property, plant and equipment		156,866		167,256
Construction-in-progress		88,899		154,852
Total property, plant and equipment		1,676,117		1,930,148
Less accumulated depreciation		(225,336)		(226,594)
Property, plant and equipment, net		1,450,781		1,703,554
Other Assets:				
Investment in unconsolidated subsidiary		454,427		-
Long-term derivative assets		6,749		36,798
Other, net of accumulated amortization of debt issuance costs of $9,228 and $5,246		20,874		13,880
Total other assets		482,050		50,678
Intangible Assets and Goodwill:				
Intangible assets, net of accumulated amortization of $30,732 and $22,667		200,491		205,646
Goodwill		228,114		262,358
Total intangible assets and goodwill		428,605		468,004
TOTAL ASSETS	$	2,513,930	$	2,458,639
LIABILITIES & PARTNERS' CAPITAL AND NONCONTROLLING INTEREST				
Current Liabilities:				
Trade accounts payable		28,014		65,483
Accrued cost of gas and liquids		48,304		76,599
Related party payables		853		-
		10,886		11,572

Deferred revenue, including related party amounts of $212 and $0				
Derivative liabilities		11,897		42,691
Escrow payable		1,510		10,031
Other current liabilities		24,723		10,574
Total current liabilities		126,187		216,950
Long-term derivative liabilities		43,759		560
Other long-term liabilities		15,433		15,487
Long-term debt, net		1,202,392		1,126,229
Commitments and contingencies				
Convertible redeemable preferred units, including accrued distributions of $1,945		49,888		-
Partners' Capital and Noncontrolling Interest:				
Common units (81,761,105 and 55,519,903 units authorized; 81,116,978 and 54,796,701 units issued and outstanding at September 30, 2009 and December 31, 2008)		1,031,894		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		13,629		29,283
Accumulated other comprehensive income		16,691		67,440
Noncontrolling interest		14,057		13,161
Total partners' capital and noncontrolling interest		1,076,271		1,099,413
TOTAL LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST	$	2,513,930	$	2,458,639

See accompanying notes to condensed consolidated financial statements

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

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
REVENUES				
Gas sales	$97,597	$323,411	$352,390	$922,872
NGL sales	66,543	120,538	173,803	355,558
Gathering, transportation and other fees, including related party amounts of $3,823, $939, $8,300, and $2,865	66,278	74,267	208,356	206,429
Net realized and unrealized gain (loss) from derivatives	12,292	6,817	39,262	(39,600)
Other	7,872	22,142	20,291	53,856
Total revenues	250,582	547,175	794,102	1,499,115
OPERATING COSTS AND EXPENSES				
Cost of sales, including related party amounts of $4,575, $632, $6,275, and $1,878	155,586	408,165	495,461	1,168,441
Operation and maintenance	32,139	33,688	100,154	95,049
General and administrative	14,126	13,976	43,331	38,784
Loss (gain) on asset sales, net of costs of $0, $0, $5,530 and $0	(109)	(34)	(133,389)	434
Management services termination fee	-	-	-	3,888
Transaction expenses	-	2	-	536
Depreciation and amortization	27,009	26,422	81,134	74,638
Total operating costs and expenses	228,751	482,219	586,691	1,381,770
OPERATING INCOME	21,831	64,956	207,411	117,345
Income from unconsolidated subsidiary	3,532	-	5,455	-
Interest expense, net	(22,173)	(16,072)	(55,968)	(48,261)
Other income and deductions, net	(13,929)	118	(13,673)	450
(LOSS) INCOME BEFORE INCOME TAXES	(10,739)	49,002	143,225	69,534
Income tax (benefit) expense	(196)	(67)	(611)	142
NET (LOSS) INCOME	(10,543)	49,069	143,836	69,392
Net loss (income) attributable to noncontrolling interest	39	(162)	(61)	(165)
NET (LOSS) INCOME ATTRIBUTABLE TO REGENCY ENERGY PARTNERS LP	$(10,504)	$48,907	$143,775	$69,227
Amounts attributable to convertible redeemable preferred units	1,996	-	1,996	-
General partner's interest, including IDR	372	1,506	4,646	3,140
Allocation of net (loss) income to non-vested common units	(134)	448	1,083	611

Beneficial conversion feature for Class D common units	-	1,887	820	5,312
Limited partners' interest	$(12,738)	$45,066	$135,230	$60,164
Basic and Diluted (loss) earnings per unit:				
Amount allocated to common and subordinated units	$(12,738)	$45,066	$135,230	$60,164
Weighted average number of common and subordinated units outstanding	80,637,783	70,043,614	79,498,936	63,839,053
Basic (loss) income per common and subordinated unit	$ (0.16)	$0.64	$1.70	$0.94
Diluted (loss) income per common and subordinated unit	$ (0.16)	$0.61	$1.69	$0.89
Distributions per unit	$0.445	$0.445	$1.335	$1.31
Amount allocated to Class D common units	$-	$1,887	$820	$5,312
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	$-	$-	$0.11	$0.73
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 September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Net (loss) income	$(10,543)	$49,069	$143,836	$69,392
Net hedging amounts reclassified to earnings	(11,470)	14,787	(39,364)	40,389
Net change in fair value of cash flow hedges	(2,144)	55,182	(11,385)	5,277
Comprehensive (loss) income	$(24,157)	$119,038	$93,087	$115,058
Comprehensive (loss) income attributable to noncontrolling interest	(39)	162	61	165
Comprehensive (loss) income attributable to Regency Energy Partners LP	$(24,118)	$118,876	$93,026	$114,893

See accompanying notes to condensed consolidated financial statements

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

	Nine Months Ended September 30, 2009	2008
OPERATING ACTIVITIES		
Net income	$ 143,836	$ 69,392
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization, including debt issuance cost amortization	85,666	76,751
Noncash income from unconsolidated subsidiary	(268)	-
Derivative valuation changes	3,040	(1,007)
Loss (gain) on asset sales, net	(133,389)	434
Unit based compensation expenses	4,361	3,087
Gain on insurance settlements	-	(3,282)
Cash flow changes in current assets and liabilities:		
Trade accounts receivable, accrued revenues, and related party receivables	32,121	(11,084)
Other current assets	14,478	38
Trade accounts payable, accrued cost of gas and liquids, and related party payables	(47,943)	(11,125)
Other current liabilities	5,628	22,448
Other assets and liabilities	(417)	3,628
Net cash flows provided by operating activities	107,113	149,280
INVESTING ACTIVITIES		
Capital expenditures	(163,889)	(243,660)
Acquisitions	(63,000)	(577,344)
Proceeds from asset sales	100,103	696
Proceeds from insurance settlements	-	3,282
Net cash flows used in investing activities	(126,786)	(817,026)
FINANCING ACTIVITIES		
Net (repayments) borrowings under revolving credit facilities	(160,627)	525,000
Proceeds from issuance of senior notes, net of discount	236,240	-
Debt issuance costs	(12,121)	(2,925)
Partner contributions	-	11,753
Partner distributions	(109,118)	(86,448)
Proceeds from option exercises	-	2,700
Proceeds from equity issuances, net of issuance costs	76,800	199,514

Net cash flows provided by financing activities		31,174		649,594
Net increase (decrease) in cash and cash equivalents		11,501		(18,152)
Cash and cash equivalents at beginning of period		599		32,971
Cash and cash equivalents at end of period	$	12,100	$	14,819
Supplemental cash flow information:				
Interest paid, net of amounts capitalized	$	35,258	$	37,634
Income taxes paid		-		596
Non-cash capital expenditures in accounts payable		3,342		24,871
Issuance of common units for an acquisition		-		219,590
Release of escrow payable from restricted cash		-		4,487
Contribution of RIGS to HPC		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)

	Units			Regency Energy Partners LP					
	Common	Class D	Subordinated	Common Unitholders	Class D Unitholders	Subordinated Unitholders	General Partner Interest	Accumulated Other Comprehensive Income	Noncontroll 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 restricted common units, net of forfeitures	(60,125)	-	-	-	-	-	-	-	-
Conversion of subordinated units	19,103,896		(19,103,896)	(1,391)	-	1,391	-	-	-
Unit based compensation expenses	-	-	-	4,361	-	-	-	-	-
Accrued distributions to phantom units	-	-	-	(114)	-	-	-	-	-
Acquisition of assets between entities under common control in excess of historical cost	-	-	-	-	-	-	(10,197)	-	-
Partner distributions	-	-	-	(105,128)	-	-	(3,990)	-	-
Net income	-	-	-	138,309	820	-	4,646	-	61
Conversion of Class D common units	7,276,506	(7,276,506)	-	227,579	(227,579)	-	-	-	-
Contributions from noncontrolling interest	-	-	-	-	-	-	-	-	835
Accrued distributions to	-	-	-	(1,906)	-	-	(39)	-	-

convertible redeemable preferred unitholders									
Accretion of redeemable preferred units	-	-	-	(50)	-	-	(1)	-	-
Net cash flow hedge amounts reclassified to earnings	-	-	-	-	-	-	-	(39,364)	-
Net change in fair value of cash flow hedges	-	-	-	-	-	-	-	(11,385)	-
Balance - September 30, 2009	81,116,978	-	-	$1,031,894	$-	$-	$13,629	$16,691	$14,057

See accompanying notes to condensed consolidated financial statements

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Regency Energy Partners LP
Notes to Unaudited Condensed Consolidated Financial Statements

1. Organization and Summary of Significant Accounting Policies
Organization. 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 nine months ended September 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 of 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	Contracts	Trade Names (in thousands)	Customer Relations	Total
Balance at December 31, 2008	$ 8,582	$ 126,799	$ 32,848	$ 37,417	$ 205,646
Disposals	(2,921)	-	-	-	(2,921)
Other	-	7,000	-	-	7,000
Amortization	(441)	(1,755)	(5,474)	(1,564)	(9,234)
Balance at September 30, 2009	$ 5,220	$ 132,044	$ 27,374	$ 35,853	$ 200,491

The weighted average amortization period for permits and licenses, customer contracts, trade names, and customer relations are 15, 23, 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)
2009 (remaining)	$ 3,138
2010	12,553

2011	11,295
2012	11,002
2013	11,002

Revision to Partners' Capital Accounts. In 2009, the Partnership revised the allocation of net income between the general partner and common unitholders from the third quarter of 2008 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 guidance which significantly changed the accounting for business acquisitions both during the period of the acquisition and in subsequent periods. The Partnership adopted this guidance on January 1, 2009.

In December 2007, the FASB issued guidance which significantly changed the accounting and reporting related to noncontrolling interests in a consolidated subsidiary. The Partnership adopted this guidance for all periods presented. This guidance 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 guidance which defines how to allocate net income among the various classes of equity, including IDRs. The guidance became effective on January 1, 2009. Earlier application was not permitted; however this guidance must be applied retrospectively for all financial statements presented. The adoption of this guidance changed 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 IDRs 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 March 2008, the FASB issued guidance which required enhanced disclosures about derivative and hedging activities. The Partnership adopted this guidance on January 1, 2009 and the adoption had no impact on its financial position, results of operations or cash flows.

In April 2008, FASB issued guidance 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 this guidance is to better match the useful life of intangible assets to the cash flow generated. The guidance became effective on January 1, 2009. The adoption of this guidance did not impact the Partnership's financial position, results of operations or cash flows.

In June 2008, the FASB issued guidance which determined whether instruments granted in share-based payment transactions are participating securities and is effective for fiscal years beginning after December 15, 2008. The adoption of this guidance was applied retrospectively and had an immaterial impact on the Partnership's earnings per unit.

In April 2009, the FASB issued guidance about interim disclosures about fair value of financial instruments which was adopted July 1, 2009. This guidance had no impact on the Partnership's financial position, results of operations or cash flows.

In May 2009, the FASB issued guidance requiring public entities to evaluate subsequent events through the date through which financial statements are issued. The adoption of this guidance on January 1, 2009 did not impact the Partnership's financial position, results of operations or cash flows.

In June 2009, the FASB issued guidance that significantly changes the consolidation model for variable interest entities. The guidance is effective for annual reporting periods that begin after November 15, 2009, and for interim periods within that first annual reporting period. The Partnership has evaluated this guidance and determined that its adoption on January 1, 2010 will have no impact on the Partnership's financial position, results of operations or cash flows.

In June 2009, the FASB issued "The FASB Accounting Standards Codification TM and the Hierarchy of Generally Accepted Accounting Principles" (the "Codification"). The Codification is the single source for GAAP that integrates existing standards and organizes them into accounting topics and is not intended to change GAAP but will change how GAAP is referenced. The Codification is 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 (Loss) 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. This 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.

On September 2, 2009, the Partnership issued 4,371,586 Series A Cumulative Convertible Preferred Units ("Convertible Redeemable Preferred Units"). The Convertible Redeemable Preferred Units will receive fixed quarterly cash distributions of $0.445 per unit beginning with the quarter ending March 31, 2010. Distributions for the quarters ending September 30, 2009 and December 31, 2009 will be accrued but not paid, effectively increasing the conversion value of the Convertible Redeemable Preferred Units. Distributions are cumulative, and must be paid before any distributions to the general partner and common unitholders. For the purpose of calculating income per limited partner unit, any form of distributions, whether paid or not, as well as the accretion of the Convertible Redeemable Preferred Units, are treated as a reduction in net income available to the general partner and limited partner interests.

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

	For the Three Months Ended September 30, 2009			For the Three Months Ended September 30, 2008		
	(Loss) Income (Numerator)	Units (Denominator)	Per-Unit Amount	Income (Numerator)	Units (Denominator)	Per-Unit Amount
	(in thousands except unit and per unit data)					
Basic (Loss) Earnings per Unit						
Net (loss) income attributable to Limited Partner interests	$ (12,738)	80,637,783	$ (0.16)	$ 45,066	70,043,614	$ 0.64
Effect of Dilutive Securities						
Non-vested common units	(134)	-		-	-	
Common unit options	-	-		-	37,969	
Phantom units	-	-		-	-	
Class D common units	-	-		1,887	7,276,506	
Diluted (Loss) Earnings per Unit	$ (12,872)	80,637,783	$ (0.16)	$ 46,953	77,358,089	$ 0.61

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.

For the Nine Months Ended September 30, 2009			For the Nine Months Ended September 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	$ 135,230	79,498,936	$ 1.70	$ 60,164	63,839,053	$ 0.94
Effect of Dilutive Securities						
Common unit options	-	-		-	111,134	
Phantom units	-	32,692		-	-	
Class D common units	820	1,066,155		5,312	7,276,506	
Class E common units	-	-		-	2,161,789	
Diluted Earnings per Unit	$ 136,050	80,597,783	$ 1.69	$ 65,476	73,388,482	$ 0.89

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.

Anti-dilutive securities:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Non-vested common units	-	18,331	-	40,654
Phantom units	250,258	-	-	-
Convertible redeemable preferred units	1,378,000	-	464,381	-

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 joint venture arrangement among Regency HIG, EFS Haynesville, LLC, and the Alinda Investors. The Partnership contributed RIGS, which owns the Regency Intrastate Gas System, valued at $401,356,000, to HPC, in exchange for a 38 percent interest in HPC. EFS Haynesville and Alinda Investors contributed $126,928,000 and $528,284,000 in cash, respectively, to HPC in return for a 12 percent and a 50 percent interest, respectively. 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.

On September 2, 2009, the Partnership purchased a five percent interest in HPC from EFS Haynesville for $63,000,000, increasing the Partnership's ownership percentage from 38 percent to 43 percent. Because the transaction occurred between two entities that are under common control, partners' capital was reduced by $10,197,000, which represented a deemed distribution of the excess purchase price over EFS Haynesville's carrying amount.

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 as well as the acquisition of additional five percent HPC interest 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 Nine Months Ended	
	September 30, 2009	September 30, 2008	September 30, 2009	September 30, 2008
	(in thousands except unit and per unit data)			
Revenue	$ 250,582	$ 534,794	$ 782,129	$ 1,470,588
Net income (loss) attributable to Regency Energy Partners LP	$ (10,158)	$ 43,252	$ 6,579	$ 189,833
Less:				
Amounts attributable to convertible redeemable preferred units	1,996	-	1,996	-
General partner's interest, including IDR	378	1,392	1,901	5,552
Allocation of net income to non-vested common units	(132)	394	(98)	2,013
Beneficial conversion feature for Class D common units	-	1,887	820	5,312
Limited partners' interest	$ (12,400)	$ 39,579	$ 1,960	$ 176,956
Basic and Diluted earnings (loss) per unit:				
Amount allocated to common and subordinated	$ (12,404)	$ 39,579	$ 1,956	$ 176,956

units									
Weighted average number of common and subordinated units outstanding		80,637,783			70,043,532		79,498,936		63,838,515
Basic income (loss) per common and subordinated unit	$	(0.15	)	$	0.57	$	0.02	$	2.77
Diluted income (loss) per common and subordinated unit	$	(0.15	)	$	0.54	$	0.02	$	2.50
Distributions per unit	$	0.445		$	0.445	$	0.445	$	1.31
Amount allocated to Class D common units	$	-		$	1,887	$	820	$	5,312
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	$	0.73
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. Subsequently, on September 2, 2009, the Partnership purchased an additional five percent partner's interest in HPC from EFS Haynesville for $63,000,000. The summarized financial information of HPC as of September 30, 2009 and for the period from inception (March 18, 2009) to September 30, 2009 is disclosed below. The Partnership recognized $5,455,000 in income from unconsolidated subsidiary for its ownership interest from inception (March 18, 2009) to September 30, 2009. In addition, the Partnership received $5,187,000 of distributions from HPC during the period from March 18, 2009 to September 30, 2009.

RIGS Haynesville Partnership Co.
Condensed Balance Sheet
September 30, 2009
Unaudited
(in thousands)

		September 30, 2009
ASSETS		
Total current assets	$	191,707
Property, plant and equipment, net		761,648
Total other assets		150,200
TOTAL ASSETS	$	1,103,555
LIABILITIES & PARTNERS' CAPITAL		
Total current liabilities	$	46,558
Partners' capital		1,056,997
TOTAL LIABILITIES & PARTNERS' CAPITAL	$	1,103,555

RIGS Haynesville Partnership Co.
Condensed Income Statement
From Inception (March 18, 2009) to September 30, 2009
Unaudited
(in thousands)

		Three Months Ended September 30, 2009		March 18, 2009 to September 30, 2009
Total revenues	$	14,188	$	30,095
Total operating costs and expenses		5,702		17,160
OPERATING INCOME		8,486		12,935
Interest expense		(65)		(65)
Other income and deductions, net		597		1,209
NET INCOME	$	9,018	$	14,079

5. Derivative Instruments

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 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 its 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 price volatility. 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 its 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 NGLs, condensate and natural gas volumes produced for its account in the approximate percentages set for below:

	2009	2010	2011
NGL	99%	56%	18%
Condensate	76%	76%	18%
Natural gas	86%	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. The Partnership uses West Texas Intermediate crude oil program to hedge condensate. At September 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 NGLs, 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. In May 2009, the Partnership entered into a natural gas swap to hedge a portion of its equity exposure to natural gas for 2010. These natural gas swaps were designated as cash flow hedges.

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 September 30, 2009, the Partnership had $608,102,000 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 $6,081,000. 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 September 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 guarantee from a parent company with potentially better credit.

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 $40,719,000, which would be reduced by $10,882,000 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.

Embedded Derivatives. The Convertible Redeemable Preferred Units contain embedded derivatives, such as the holders' conversion option and the Partnership's call option. These embedded derivatives are accounted for using mark-to-market accounting treatment. Changes in the fair value are recorded in other income and deductions, net within the statement of operations. The Partnership does not expect the embedded derivatives to affect its cash flows. During the three months ended September 30, 2009, the total amount of loss recognized was $13,986,000.

Quantitative Disclosures. The Partnership expects to reclassify $12,470,000 of net hedging gains to revenues or interest expense from accumulated other comprehensive income in the next 12 months.

The Partnership's derivative assets and liabilities, including its credit risk adjustment, are detailed below as of September 30, 2009 and December 31, 2008 and for the three and nine months ended September 30, 2009 and 2008.

	Assets		Liabilities	
	September 30, 2009	December 31, 2008	September 30, 2009	December 31, 2008
	(in thousands)			
Derivatives designated as cash flow hedges				
Current amounts				
Interest rate contracts	$ -	$ -	$ 2,677	$ 4,680
Commodity contracts	19,640	59,882	3,048	-
Long-term amounts				
Interest rate contracts	-	-	-	560
Commodity contracts	2,681	13,373	99	-
Total cash flow hedging instruments	22,321	73,255	5,824	5,240
Derivatives not designated as cash flow hedges				

Current amounts				
Interest rate contracts	-	-	-	-
Commodity contracts	14,330	16,001	6,292	38,402
Long-term amounts				
Interest rate contracts	-	-	-	-
Commodity contracts	4,068	23,425	766	-
Embedded derivatives in convertible redeemable preferred units	-	-	(42,894)	-
Total derivatives not designated as cash flow hedges	18,398	39,426	(35,836)	38,402
Credit Risk Assessment				
Current amounts	(220)	(1,890)	(120)	(391)
Total derivatives	$ 40,499	$ 110,791	$ (30,132)	$ 43,251

Derivatives designated as cash flow hedges

	Three Months Ended September 30, 2009			Three Months Ended September 30, 2008		
	Interest Rate	Commodity	Total	Interest Rate	Commodity	Total
Gain (loss) recorded in accumulated OCI (Effective)	$(522)	$(3,005)	$(3,527)	$(751)	$57,444	$56,693
Gain (loss) reclassified from accumulated OCI into income (Effective)*	(1,612)	13,514	11,902	51	(14,773)	(14,722)
Gain (loss) recognized in income (Ineffective)*	-	(1,383)	(1,383)	-	1,511	1,511

	Nine Months Ended September 30, 2009			Nine Months Ended September 30, 2008		
	Interest Rate	Commodity	Total	Interest Rate	Commodity	Total
Gain (loss) recorded in accumulated OCI (Effective)	$(2,035)	$(8,501)	$(10,536)	3,693	3,581	$7,274
Gain (loss) reclassified from accumulated OCI into income (Effective)*	(4,597)	45,578	40,981	410	(40,617)	(40,207)
Gain (loss) recognized in income (Ineffective)*	-	849	849	-	1,997	1,997

Derivatives not designated as cash flow hedges

	Three Months Ended September 30, 2009			Three Months Ended September 30, 2008		
	Embedded Derivative	Commodity	Total	Embedded Derivative	Commodity	Total
Loss from dedesignation amortized from accumulated OCI into income*	$-	$(432)	$(432)	$-	$(65)	$(65)
(Loss) gain recognized in income*	(13,986)	143	(13,843)	-	19,982	19,982

	Nine Months Ended September 30, 2009			Nine Months Ended September 30, 2008		
	Embedded Derivative	Commodity	Total	Embedded Derivative	Commodity	Total
Loss from dedesignation amortized from accumulated OCI into income*	$-	$(1,617)	$(1,617)	$-	$(182)	$(182)
Loss recognized in income*	(13,986)	(6,948)	(20,934)	-	(1,908)	(1,908)

Credit risk assessment for commodity and interest rate swaps	Three Months Ended		Nine Months Ended	
	September 30, 2009	September 30, 2008	September 30, 2009	September 30, 2008
Gain recognized in income*	$450	$162	$1,400	$1,110

* Gain and loss related to commodity swaps, interest swaps and embedded derivatives were included in revenue, interest expense, and other income and deductions, net, respectively, in the Partnership's condensed consolidated statements of operations for the three and nine months of September 30, 2009 and 2008.

6. Long-term Debt, net

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

	September 30, 2009	December 31, 2008
	(in thousands)	
Senior notes	$ 594,290	$ 357,500
Revolving loans	608,102	768,729
Total	1,202,392	1,126,229
Less: current portion	-	-
Long-term debt	$ 1,202,392	$ 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	(608,102	(768,729)
Letters of credit	(16,257)	(16,257)
Total available	$ 268,611	$ 106,368

On May 20, 2009, the Partnership and Finance Corp. issued $250,000,000 senior notes in a private placement that matures 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.

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. Beginning June 1, 2013, the Partnership may redeem all or part of the notes for the principal amount plus a declining premium until June 1, 2015, and thereafter at par, plus accrued and unpaid interest. 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 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 a change of control, each noteholder 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. 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 carrying value of the Partnership's senior notes due 2016 is as follows.

	September 30, 2009	December 31, 2008
	(in thousands)	
Principal amount	$ 250,000	$ -
Less: Unamortized discount	(13,210)	-
Carrying value	$ 236,790	$ -

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 a result, a subsidiary of Lehman that is a committed lender under our Credit Facility has declined requests to honor its commitment to lend. The total amount committed by Lehman was $20,000,000 and as of September 30, 2009, the Partnership had borrowed all but $7,030,000 of that amount. Since Lehman has declined requests to honor its remaining commitment, our total size of the Credit Facility's capacity has been reduced from $900,000,000 to $892,970,000. Further, if the Partnership makes repayments of loans against the Credit 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 6.44 percent and 6.37 percent for the nine months ended September 30, 2009 and 2008, respectively, and 7.42 percent and 6.15 percent for the three months ended September 30, 2009 and 2008, respectively. The senior notes pay fixed interest rates and the weighted average rate is 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 September 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 the Partnership's 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. In February 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. In April 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, Kansas processing plant. 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, the Partnership no longer delivered any helium to Keyes. In this suit, Keyes alleges it is entitled to an unspecified amount of damages for the costs of covering its purchases of helium. Discovery ended in October 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. Caddo Gas 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 of 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 filed a claim in the bankruptcy proceeding relating to the environmental remediation work at the Plants. Tronox has thus far continued its remediation efforts at the Regency facilities.

8. Convertible Redeemable Preferred Units

On September 2, 2009, the Partnership issued 4,371,586 Convertible Redeemable Preferred Units at a price of $18.30 per unit, less a four percent discount of $3,200,000, for net proceeds of $76,800,000. The Convertible Redeemable Preferred Units are convertible to common units under terms described below, and if outstanding, are redeemable on September 2, 2029. The Convertible Redeemable Preferred Units will receive fixed quarterly cash distributions of $0.445 per unit beginning with the quarter ending March 31, 2010.

Distributions on the Convertible Redeemable Preferred Units will be accrued for the quarters ending September 30, 2009 and December 31, 2009 (and not paid in cash) and will result in an increase in the number of common units issuable upon conversion. If on any distribution payment date beginning March 31, 2010, the Partnership (1) fails to pay distributions on the Convertible Redeemable Preferred Units, (2) reduces the distributions on the common units to zero and (3) is prohibited by its material financing agreements from paying cash distributions, such distributions shall automatically accrue and accumulate until paid in cash. If the Partnership has failed to pay cash distributions in full for two quarters (whether or not consecutive) from and including the quarter ending on March 31, 2010, then if the Partnership fails to pay cash distributions on the Convertible Redeemable Preferred Units, all future distributions on the Convertible Redeemable Preferred Units that are accrued rather than being paid in cash by the Partnership will consist of the following: (1) $0.35375 per Convertible Redeemable Preferred Unit per quarter, (2) $0.09125 per Convertible Redeemable Preferred Unit per quarter (the “Common Unit Distribution Amount”), payable solely in common units, and (3) $0.09125 per Convertible Redeemable Preferred Unit per quarter (the “PIK Distribution Additional Amount”), payable solely in common units. The total number of common units payable in connection with the Common Unit Additional Amount or the PIK Distribution Additional Amount cannot exceed 1,600,000 in any period of twenty consecutive fiscal quarters.

Upon the Partnership’s breach of certain covenants related to the 9.375 percent Senior Notes due 2016 (a “Covenant Default”), the holders of the Convertible Redeemable Preferred Units will be entitled to an increase of $0.1825 per quarterly distribution, payable solely in common units (the “Covenant Default Additional Amount”). All accumulated and unpaid distributions will accrue interest (i) at a rate of 2.432 percent per quarter, or (ii) if the Partnership has failed to pay all PIK Distribution Additional Amounts or Covenant Default Additional Amounts or any Covenant Default has occurred and is continuing, at a rate of 3.429 percent per quarter while such failure to pay or such Covenant Default continues.

The Convertible Redeemable Preferred Units are convertible, at the holder's option, into common units commencing on March 2, 2010, provided that the holder must request conversion of at least 375,000 Convertible Redeemable Preferred Units. The conversion price will initially be $18.30, subject to adjustment for customary events (such as unit splits) and until December 31, 2011, based on a weighted average formula in the event the Partnership issues any common units (or securities convertible or exercisable into common units) at a per Common Unit price below $16.47 per common unit. The number of common units issuable is equal to the issue price of the Convertible Redeemable Preferred Units (i.e. $18.30) being converted plus all accrued but unpaid distributions and accrued but unpaid interest thereon (the "Redeemable Face Amount"), divided by the applicable conversion price.

Commencing on September 2, 2014, if at any time the volume-weighted average trading price of the common units over the trailing 20-trading day period (the "VWAP Price") is less than the then-applicable conversion price, the conversion ratio will be increased to: the quotient of (1) the Redeemable Face Amount on the date that the holder's conversion notice is delivered, divided by (2) the product of (x) the VWAP Price set forth in the applicable conversion notice and (y) 91 percent, but will not be less than $10.

Also commencing on September 2, 2014, the Partnership will have the right at any time to convert all or part of the Convertible Redeemable Preferred Units into common units, if (1) the daily volume-weighted average trading price of the common units is greater than 150 percent of the then-applicable conversion price for twenty (20) out of the trailing thirty (30) trading days, and (2) certain minimum public float and trading volume requirements are satisfied.

The Convertible Redeemable Preferred Units are mandatorily redeemable on September 2, 2029 for $80,000,000 plus all accrued but unpaid distributions thereon (the "Series A Liquidation Value").

In the event of a change of control followed by a ratings decline, the Partnership will be required to make an offer to the holders of the Convertible Redeemable Preferred Units to purchase their Convertible Redeemable Preferred Units for an amount equal to 101 percent of their Series A Liquidation Value. In addition, until and including the fifth anniversary of the issuance date, in the event of certain business combinations or other transactions involving the Partnership in which the holders of common units receive cash consideration exclusively in exchange for their common units (a "Cash Event"), the Partnership must use commercially reasonable efforts to ensure that the holders of the Convertible Redeemable Preferred Units will be entitled to receive a security issued by the surviving entity in the Cash Event with comparable powers, preferences and rights to the Convertible Redeemable Preferred Units. If the Partnership is unable to ensure that the holders of the Convertible Redeemable Preferred Units will be entitled to receive such a security, then the Partnership will be required to make an offer to the holders of the Convertible Redeemable Preferred Units to purchase their Convertible Redeemable Preferred Units for an amount equal to 120 percent of their Series A Liquidation Value. If the Partnership enters into any recapitalization, reorganization, consolidation, merger, spin-off that is not a Cash Event, the Partnership will make appropriate provisions to ensure that the holders of the Convertible Redeemable Preferred Units receive a security with comparable powers, preferences and rights to the Convertible Redeemable Preferred Units upon consummation of such transaction.

The September 30, 2009 accrued distributions of $1,945,000 was added to the value of Convertible Redeemable Preferred Units and will increase the number of common units that Convertible Redeemable Preferred may be converted beginning March 2, 2010 to 4,477,890 upon conversion.

Net proceeds from the issuance of Convertible Redeemable Preferred Units on September 2, 2009 was $76,800,000, of which $28,908,000 was allocated to the initial fair value of the embedded derivatives and recorded into long-term derivative liabilities on the balance sheet. The remaining $47,892,000 represented the initial value of the Convertible Redeemable Preferred Units and will be accreted to $80,000,000 by deducting the accretion amounts from partners' capital over 20 years.

The following table presents the change in Convertible Redeemable Preferred Units for the nine months ended September 30, 2009.

	For the Nine Months Ended September 30, 2009 (in thousands)
Beginning Balance	$ -
Issuance	47,892
Accretion	51
Accrued distribution	1,945
Ending Balance	$ 49,888

9. 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 $8,289,000, $7,284,0000, $24,563,000, and $22,605,000 were recorded in the Partnership's financial statements during the three and nine months ended September 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 three and nine months ended September 30, 2009 and 2008, GE EFS received cash distributions of $1,865,000, $5,429,000, $1,679,000 and $2,801,000.

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. The Partnership also incurs expenditures on behalf of HPC and these amounts are billed to HPC on a monthly basis. Additionally, the Partnership's gathering and processing and contract compression segments provide processing and contract compression services to HPC. As of and for the three and nine months ended September 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.

On September 2, 2009, the Partnership purchased 52,650 units representing a five percent partner's interest in HPC from EFS Haynesville for $63,000,000.

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.

10. 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 initial contribution of RIGS to HPC in March 2009, as well as the subsequent acquisition of an additional five percent interest in HPC, the transportation segment consists exclusively of the Partnership's 43 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 September 30, 2009	$211,787	$ -	$ 36,367	$2,428	$ -	$250,582
For the three months ended September 30, 2008	500,425	9,366	36,162	1,222	-	547,175
For the nine months ended September 30, 2009	664,006	9,078	113,866	7,152	-	794,102
For the nine months ended September 30, 2008	1,372,960	29,576	94,016	2,563	-	1,499,115
Intersegment Revenue						
For the three months ended September 30, 2009	(3)	-	1,208	87	(1,292)	-
For the three months ended September 30, 2008	(4,567)	4,547	6,549	75	(6,604)	-
For the nine months ended September 30, 2009	(8,755)	4,933	2,993	232	597	-
For the nine months ended September 30, 2008	10,979	10,906	6,831	253	(28,969)	-
Cost of Sales						
For the three months ended September 30, 2009	152,283	-	3,490	(103)	(84)	155,586
For the three months ended September 30, 2008	407,458	(2,754)	3,423	3	35	408,165
For the nine months ended September 30, 2009	479,567	2,297	9,994	13	3,590	495,461
For the nine months ended September 30, 2008	1,192,303	(10,422)	8,695	3	(22,138)	1,168,441
Segment Margin						
For the three months ended September 30, 2009	59,501	-	34,085	2,618	(1,208)	94,996
For the three months ended September 30, 2008	88,400	16,667	39,288	1,294	(6,639)	139,010
For the nine months ended September 30, 2009	175,684	11,714	106,865	7,371	(2,993)	298,641
For the nine months ended September 30, 2008	191,636	50,904	92,152	2,813	(6,831)	330,674
Operation and Maintenance						
For the three months ended September 30, 2009	22,518	-	11,012	170	(1,561)	32,139
For the three months ended September 30, 2008	25,225	(1,007)	16,020	73	(6,623)	33,688
For the nine months ended September 30, 2009	66,866	2,112	35,040	302	(4,166)	100,154

For the nine months ended September 30, 2008	63,293	1,833	36,253	461	(6,791)	95,049
Depreciation and Amortization						
For the three months ended September 30, 2009	16,881	-	9,271	857	-	27,009
For the three months ended September 30, 2008	14,865	3,506	7,537	514	-	26,422
For the nine months ended September 30, 2009	50,015	2,448	26,253	2,418	-	81,134
For the nine months ended September 30, 2008	42,286	10,439	20,370	1,543	-	74,638
Assets						
September 30, 2009	1,015,823	454,562	924,142	119,403	-	2,513,930
December 31, 2008	1,103,770	325,310	881,552	148,007	-	2,458,639
Investment in Unconsolidated Subsidiary						
September 30, 2009	-	454,427	-	-	-	454,427
December 31, 2008	-	-	-	-	-	-
Goodwill						
September 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 nine months ended September 30, 2009	55,969	22,367	83,579	1,974	-	163,889
For the nine months ended September 30, 2008	108,330	92	133,367	1,871	-	243,660

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

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(in thousands)			
Net (loss) income attributable to Regency Energy Partners LP	$ (10,504)	$ 48,907	$ 143,775	$ 69,227
Add (deduct):				
Operation and maintenance	32,139	33,688	100,154	95,049
General and administrative	14,126	13,976	43,331	38,784
(Gain) loss on asset sales, net of costs	(109)	(34)	(133,389)	434
Management services termination fee	-	-	-	3,888
Transaction expenses	-	2	-	536
Depreciation and amortization	27,009	26,422	81,134	74,638
Income from unconsolidated subsidiary	(3,532)	-	(5,455)	-
Interest expense, net	22,173	16,072	55,968	48,261
Other income and deductions, net	13,929	(118)	13,673	(450)
Income tax (benefit) expense	(196)	(67)	(611)	142
Net (loss) income attributable to the noncontrolling interest	(39)	162	61	165
Total segment margin	$ 94,996	$ 139,010	$ 298,641	$ 330,674

11. 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 $10,918,000 of compensation expense related to non-vested units over a weighted average period of approximately 2.16 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 nine months ended September 30, 2009 are 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	(173,416)	29.89
Forfeited or expired	(84,625)	28.44
Outstanding at end of period	470,509	28.23

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	(123,300)	20.88		
Outstanding at end of period	308,618	21.49	6.55	-
Exercisable at end of period	308,618	$ 21.49		-

* 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 nine months ended September 30, 2009, the Partnership awarded 303,200 phantom units to senior management and certain key employees. These phantom units are in substance two grants composed of (1) service condition grants (also defined as "time-based grants" in the LTIP plan document) with graded vesting occurring on March 15 of each of the following three years; and (2) market condition grants (also defined as "performance-based grants" in the LTIP plan document) with cliff vesting based upon the Partnership's relative ranking in total unitholder return among 20 peer companies, which peer companies are 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. Upon a change in control, the market condition based grants will convert to common units at 150 percent and the service condition grants will conver to common on a one-for-one basis. 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 2.7 years. During the three and nine months ended September 30, 2009, the Partnership recognized $157,000 and $204,000 of expense, respectively, which is reflected in general and administrative expense on the condensed consolidated income statement.

The following table presents phantom unit activity for the nine months ended September 30, 2009.

Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	-	$ -
Service condition grants	128,480	13.17
Market condition grants	174,720	4.64
Vested service condition	-	-
Vested market condition	-	-
Forfeited service condition	(1,800)	-
Forfeited market condition	(2,700)	-
Total outstanding at end of period	298,700	$ 8.38

12. Fair Value Measures

On January 1, 2008, the Partnership adopted the fair value measurement provisions for financial assets and liabilities and on January 1, 2009, the Partnership applied the fair value measurement provisions to non-financial assets and liabilities, such as goodwill, indefinite-lived intangible assets, property, plant and equipment and asset retirement obligations. These provisions establish 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.

Entities are encouraged 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.

Derivatives. The Partnership's financial assets and liabilities measured at fair value on a recurring basis are derivatives related to interest rate and commodity swaps and embedded derivatives in the Convertible Redeemable Preferred Units. Derivatives related to interest rate and commodity swaps 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. Derivatives related to Convertible Redeemable Preferred Units are valued using a binomial lattice model. The market inputs utilized in the model include credit spread, probabilities of the occurrence of certain events, dividend yield, and expected volatility, and are classified as Level 3 in the hierarchy.

The following table presents the Partnership's derivative assets and liabilities measured at fair value on a recurring basis.

	September 30, 2009		December 31, 2008	
	Assets	Liabilities	Assets	Liabilities
	(in thousands)			
Level 1	$ -	$ -	$ -	$ -
Level 2	40,499	12,762	110,791	43,251
Level 3	-	42,894	-	-

Total	$ 40,499	$ 55,656	$ 110,791	$ 43,251

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The following table presents the changes in Level 3 derivatives measured on a recurring basis for the three and nine months ended September 30, 2009. There were no Level 3 derivatives in 2008.

	Derivatives related to Convertible Redeemable Preferred Units	
	For the Three Months Ended September 30, 2009	For the Nine Months Ended September 30, 2009
	(in thousands)	
Beginning Balance	$ -	$ -
Issuance	28,908	28,908
Net unrealized (gains) losses included in other income and deductions, net	13,986	13,986
Ending Balance	$ 42,894	$ 42,894

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. Long-term debt (other than the senior notes) is comprised of borrowings under which, interest accrues 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 $363,756,250 and $258,750,000, respectively, as of September 30, 2009.

13. Subsequent Events

On October 27, 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 $633,000, with respect to incentive distribution rights, payable on November 13, 2009 to unitholders of record at the close of business on November 6, 2009.

The Partnership evaluated subsequent events up to and including November 9, 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 master 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.

Partnership. On September 2, 2009, we issued 4,371,586 Series A Cumulative Convertible Preferred Units ("Convertible Redeemable Preferred Units") at a price of $18.30 per unit, less a four percent discount of $3,200,000, for net proceeds of $76,800,000.

On September 11, 2009, we announced the Logansport Expansion which will extend our Nexus gathering system. This project will add approximately 300 MMcf/d of gathering capacity and is anticipated to cost $46,500,000. The Logansport Expansion will be funded from the proceeds of the recently issued Convertible Redeemable Preferred Units and our revolving credit facility.

Joint Venture. On March 17, 2009, we announced the completion of the transactions included in the Contribution Agreement relating to a joint venture among Regency HIG, EFS Haynesville and the Alinda Investors. We contributed RIGS, which owned the Regency Intrastate Gas System, valued at $401,356,000, to HPC, in exchange for a 38 percent interest in HPC. EFS Haynesville and the Alinda Investors contributed $126,928,000 and $528,284,000 in cash, respectively, to HPC in return for a 12 percent and a 50 percent interest, respectively. On September 2, 2009, we purchased an additional five percent partner's interest in HPC from EFS Haynesville for $63,000,000, increasing our ownership percentage to 43 percent.

HPC was formed to finance the construction and development of the expansion of our existing natural gas pipeline in north Louisiana and to operate the Regency Intrastate Gas System.

On September 14, 2009, HPC announced plans to construct a $47,000,000 pipeline extension of the Haynesville Expansion Project. This extension, which is called the Red River Lateral, will add approximately 100,000 MMbtu/d of capacity to the Haynesville Expansion Project, bringing the total project capacity to approximately 1.2 Bcf/d. Substantially all of the incremental capacity on the Red River Lateral has been contracted to third parties.

Drilling and Pricing Pressure Trends.

General. We continue to see a lower level of drilling activity in certain operating regions compared to last year. As long as natural 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 for natural gas 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 and decreased drilling activity, our natural gas contract compression segment is currently experiencing a challenging environment. Overall, revenue generating horsepower decreased by three percent for the three months ended September 30, 2009, compared to levels as of June 30, 2009, and we anticipate continued challenges in redeploying compression that comes up for renewal as well as deploying newly-fabricated 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 43 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. We use 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 primary 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 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 included 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 was fee-based with little or no commodity price risk.

Since 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 an unconsolidated subsidiary. Because of the significance of HPC to the Partnership, we are providing a separate 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 equal to 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 10, Segment Information, within the condensed consolidated financial statements included in Item 1 of this report.

Operation and Maintenance Expense. Operation and maintenance expense is a separate measure that we use to evaluate the operating performance of field operations. Direct labor, insurance, property taxes, repair and maintenance, utilities and contract services make up 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.

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(in thousands)	
Net cash flows provided by operating activities	$ 107,113	$ 149,280
Add (deduct):		
Depreciation and amortization, including debt issuance cost amortization	(85,666)	(76,751)
Noncash income from unconsolidated subsidiary	268	-
Derivative portfolio valuation changes	(3,040)	1,007
Gain (loss) on asset sales, net	133,389	(434)
Unit based compensation expenses	(4,361)	(3,087)
Gain on insurance settlement	-	3,282
Changes in current assets and liabilities:		
Trade accounts receivables, accrued revenues and related party receivables	(32,121)	11,084
Other current assets	(14,478)	(38)
Trade accounts payable, accrued cost of gas and liquids, and related party payables	47,943	11,125
Other current liabilities	(5,628)	(22,448)
Other assets and liablities	417	(3,628)
Net income	$ 143,836	$ 69,392
Add:		
Interest expense, net	55,968	48,261
Depreciation and amortization	81,134	74,638
Income tax (benefit) expense	(611)	142
EBITDA	$ 280,327	$ 192,433

CASH DISTRIBUTIONS. On October 27, 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 $633,000, with respect to incentive distribution rights, payable on November

13, 2009 to unitholders of record at the close of business on November 6, 2009.

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

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Change	Percent
	(in thousands except percentages and volume data)			
Revenues	$ 250,582	$ 547,175	$ (296,593)	54 %
Cost of sales	155,586	408,165	(252,579)	62
Total segment margin (1)	94,996	139,010	(44,014)	32
Operation and maintenance	32,139	33,688	(1,549)	5
General and administrative	14,126	13,976	150	1
Gain on asset sales, net	(109)	(34)	(75)	221
Transaction expense	-	2	(2)	N/M
Depreciation and amortization	27,009	26,422	587	2
Operating income	21,831	64,956	(43,125)	66
Income from unconsolidated subsidiary	3,532	-	3,532	N/M
Interest expense, net	(22,173)	(16,072)	(6,101)	38
Other income and deductions, net	(13,929)	118	(14,047)	11,904
Income tax benefit	(196)	(67)	(129)	193
Net loss (income) attributable to the noncontrolling interest	39	(162)	201	124
Net (loss) income attributable to Regency Energy Partners LP	$ (10,504)	$ 48,907	(59,411)	121 %
System inlet volumes (MMbtu/d) (2)	1,518,263	1,604,655	(86,392)	5
Revenue generating horsepower (3)	743,289	742,804	485	-

(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 10, 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 September 30, 2009	September 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)	$ 59,501	$ 88,400	$ (28,899)	33 %
Operation and maintenance (4)	22,518	25,225	(2,707)	11
Operating data:				
Throughput (MMbtu/d) (5)	981,925	1,082,139	(100,214)	9
NGL gross production (Bbls/d)	21,814	21,386	428	2
Transportation Segment				
Financial data:				
Segment margin (1) (2) (3) (7)	N/A	$ 16,667	N/M	N/M
Operation and maintenance (4) (7)	N/A	(1,007)	N/M	N/M
Operating data:				
Throughput (MMbtu/d) (5) (7)	N/A	795,104	N/M	N/M
Contract Compression Segment				
Financial data:				
Segment margin (1)(2)(3)	$ 34,085	$ 39,288	$ (5,203)	13
Operation and maintenance (4)	11,012	16,020	(5,008)	31
Operating data:				
Revenue generating horsepower (6)	743,289	742,804	485	-
Average horsepower per revenue generating compression unit	836	851	(15)	2
Corporate & Others				
Financial data:				
Segment margin (1) (2) (3)	$ 2,618	$ 1,294	$ 1,324	102
Operation and maintenance (4)	170	73	97	133

(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 10, Segment Information."

(2) Segment margin differ from previously disclosed amounts due to functional reorganization of our operating segments as well as eliminations.
(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.
(7) Subsequent to March 17, 2009, we no longer report segment margin, operation and maintenance, or throughput for the transportation segment.
N/M – Not meaningful.

In addition to the revenue generating horsepower and units owned and operated by the contract compression segment disclosed below, the contract compression segment operates 158,718 horsepower owned by the gathering and processing segment as of September 30, 2009. The contract compression segment also operates 25,030 horsepower owned by HPC as of September 30, 2009.

			September 30, 2009		
Horsepower Range		Revenue Generating Horsepower	Percentage of Revenue Generating Horsepower		Number of Units
0-499		66,135	9	%	368
500-999		76,184	10	%	123
1,000	+	600,970	81	%	398
		743,289	100	%	889

			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 (Loss) Income Attributable to the Partnership. Net loss attributable to the Partnership for the three months ended September 30, 2009 was $10,504,000 compared to net income attributable to the Partnership of $48,907,000 in the three months ended September 30, 2008, a decrease of $59,411,000. The decrease was primarily due to a decrease in total segment margin of $44,014,000 caused by lower commodity prices and less volumes processed through our system in the gathering and processing segment as well as the contribution of RIGS to HPC on March 17, 2009, a decrease in other income and deductions of $14,047,000 primarily related to the non-cash value change associated with the embedded derivative related to the Convertible Redeemable Preferred Units issued on September 2, 2009, an increase of interest expense of $6,101,000 primarily associated with the issuance of $250,000,000 senior notes in May 2009 at higher interest rates, and an increase in depreciation expense of $587,000 related to organic growth projects since September 30, 2008, and was partially offset by:

- $3,532,000 of income from HPC, which was formed in March 2009; and
- $1,549,000 decrease in operation and maintenance expense, primarily due to cost control and efficiency measures.

Segment Margin. Total segment margin for the three months ended September 30, 2009 decreased by $44,014,000 compared with the three months ended September 30, 2008. This decrease was the net result of a $28,899,000 decrease in the gathering and processing segment, a $16,667,000 decrease in the transportation segment margin attributable to our contribution of RIGS to HPC on March 17, 2009, and a $5,203,000 decrease in the contract compression segment and was partially offset by an increase of $1,324,000 in the corporate and others segment. Combined segment margin varies from consolidated segment margin by $1,208,000 and $6,639,000 in the three months ended September 30, 2009 and 2008, respectively, due to intersegment eliminations. Segment margins differ from previously disclosed amounts due to the functional reorganization of our operating segments as well as eliminations.

Gathering and processing segment margin decreased to $59,501,000 in the three months ended September 30, 2009 from $88,400,000 for the three months ended September 30, 2008. The major components of the decrease were as follows:

- $16,937,000 from non-cash value changes related to certain contracts associated with our risk management program;
- $9,149,000 related to lower commodity prices compared to the 2008 price level;
- $2,096,000 related to our limited producer service; and
- $717,000 from various other sources.

Transportation segment margin decreased by $16,667,000 for the three months ended September 30, 2009; the decrease is related to the contribution of RIGS to HPC on March 17, 2009.

Contract compression segment margin decreased to $34,085,000 in the three months ended September 30, 2009 from $39,288,000 for the three months ended September 30, 2008. The decrease is primarily attributable to the decrease in inter-segment revenue which is eliminated upon consolidation.

Operation and Maintenance. Operation and maintenance expense decreased to $32,139,000 in the three months ended September 30, 2009 from $33,688,000 for the corresponding period in 2008, a five percent decrease. This net decrease in operation and maintenance expense was the result of the following factors:

- $1,334,000 decrease in materials and parts costs due to cost control and efficiency measures;
- $588,000 decrease in property tax related primarily to the contribution of RIGS to HPC; and were partially offset by
- $373,000 increase in various other operation and maintenance expenses.

General and Administrative. General and administrative expenses increased to $14,126,000 in the three months ended September 30, 2009 from $13,976,000 for the same period in 2008, a one percent increase. General and administrative expenses remained relatively flat as a result of management emphasis on cost controls.

Depreciation and Amortization. Depreciation and amortization expenses increased to $27,009,000 in the three months ended September 30, 2009 from $26,422,000 for the three months ended September 30, 2008, a two percent increase. The net increase in depreciation expense is attributed to the following factors:

- $4,093,000 increase related to various organic growth projects completed since September 30, 2008; and partially offset by a
- $3,506,000 decrease related to the contribution of RIGS to HPC.

Interest Expense, Net. Interest expense, net increased by $6,101,000, or 38 percent, in the three months ended September 30, 2009, compared to the same period in 2008. Interest expense, net increased by $3,303,000 due to higher interest rates and $2,798,000 due to increased borrowings.

Nine Months Ended September 30, 2009 vs. Nine Months Ended September 30, 2008

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008	Change	Percent
	(in thousands except percentages and volume data)			
Revenues	$ 794,102	$ 1,499,115	$ (705,013)	47 %
Cost of sales	495,461	1,168,441	(672,980)	58
Total segment margin (1)	298,641	330,674	(32,033)	10
Operation and maintenance	100,154	95,049	5,105	5
General and administrative	43,331	38,784	4,547	12
(Gain) loss on asset sales, net	(133,389)	434	(133,823)	30,835
Management services termination fee	-	3,888	(3,888)	N/M
Transaction expense	-	536	(536)	N/M
Depreciation and amortization	81,134	74,638	6,496	9
Operating income	207,411	117,345	90,066	77
Income from unconsolidated subsidiary	5,455	-	5,455	N/M
Interest expense, net	(55,968)	(48,261)	(7,707)	16
Other income and deductions, net	(13,673)	450	(14,123)	3,138
Income tax (benefit) expense	(611)	142	(753)	530
Net income attributable to the noncontrolling interest	(61)	(165)	104	63
Net income attributable to Regency Energy Partners LP	$ 143,775	$ 69,227	74,548	108 %
System inlet volumes (MMbtu/d) (2)	1,544,335	1,500,714	53,621	4
Revenue generating horsepower (3)	743,289	742,804	485	-

(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 10, 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.

	Nine Months Ended September 30, 2009	September 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)	$ 175,684	$ 191,636	$ (15,952)	8 %
Operation and maintenance (4)	66,866	63,293	3,573	6
Operating data:				
Throughput (MMbtu/d) (5)	1,001,575	998,518	3,057	0
NGL gross production (Bbls/d)	22,049	22,323	(274)	1
Transportation Segment				
Financial data:				
Segment margin (1) (2) (3)	$ 11,714	$ 50,904	$ (39,190)	77
Operation and maintenance (4)	2,112	1,833	279	15
Operating data:				
Throughput (MMbtu/d) (5)	257,239	773,562	(516,323)	67
Contract Compression Segment				
Financial data:				
Segment margin (1) (2)(3)	$ 106,865	$ 92,152	$ 14,713	16
Operation and maintenance (4)	35,040	36,253	(1,213)	3
Operating data:				
Revenue generating horsepower (6)	743,289	742,804	485	0
Average horsepower per revenue generating compression unit	836	851	(15)	2
Corporate & Others				
Financial data:				
Segment margin (1) (2) (3)	$ 7,371	$ 2,813	$ 4,558	162
Operation and maintenance (4)	302	461	(159)	34

(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 10, Segment Information".
(2) Segment margin differ from previously disclosed amounts due to functional reorganization of our operating segments as well as eliminations.
(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 nine months ended September 30, 2009 was $143,775,000 compared to $69,227,000 in the nine months ended September 30, 2008, a 108 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 contribution of RIGS to HPC, $5,455,000 in income from HPC and the absence in 2009 of $3,888,000 of management service termination fee related to the acquisition of our FrontStreet assets in 2008. These increases were partially offset by:

- A decrease in total segment margin of $32,033,000 due primarily to lower commodity prices as well as the contribution of RIGS to HPC on March 17, 2009;
- A decrease in other income and deduction of $14,123,000 primarily relates to the non-cash value change associated with the embedded derivative related to the Convertible Redeemable Preferred Units issued on September 2, 2009;
- An increase in interest expense of $7,707,000 related primarily to the issuance of $250,000,000 senior notes in May 2009 at higher interest rates and increased level of borrowing compared to 2008 levels;
- An increase in depreciation and amortization expense of $6,496,000 related primarily to organic growth projects completed since September 30, 2008;
- An increase in operation and maintenance expense of $5,105,000 primarily due to increased emphasis on the maintenance of our gathering and processing compression fleet; and
- An increase in general and administrative expenses of $4,547,000 primarily due to an increase in employee related expenses.

Segment Margin. Total segment margin for the nine months ended September 30, 2009 decreased by $32,033,000 compared with the nine months ended September 30, 2008. This decrease was attributable to a decrease of $39,190,000 in the transportation segment related to the contribution of RIGS to HPC, a decrease of $15,952,000 in the gathering and processing segment and was partially offset by an increase of $14,713,000 in the contract compression segment margin and $4,558,000 in corporate and others segment. Combined segment margin varies from consolidated segment margin by $2,993,000 and $6,831,000 for the nine months ended September 30, 2009 and 2008, respectively, due to intersegment eliminations. Segment margins differ from previously disclosed amounts due to the functional reorganization of our operating segments as well as eliminations.

Gathering and processing segment margin decreased to $175,684,000 in the nine months ended September 30, 2009 from $191,636,000 for the nine months ended September 30, 2008. The major components of this decrease were as follows:

- $24,678,000 related to lower commodity prices compared to the 2008 price levels;
- $1,204,000 decrease from various other sources primarily related to our limited producer services; and were partially offset by
- $9,930,000 increase from non-cash value change related to certain contracts associated with our risk management program.

Transportation segment margin decreased to $11,714,000 for the nine months ended September 30, 2009 from $50,904,000 for the nine months ended September 30, 2008, primarily due to the contribution of RIGS to HPC on March 17, 2009.

Contract compression segment margin increased to $106,865,000 in the nine months ended September 30, 2009 from $92,152,000 for the nine months ended September 30, 2008. The increase is primarily attributable to higher revenue generating horsepower in the first half of 2009. Contract compression segment margin is 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 $100,154,000 in the nine months ended September 30, 2009 from $95,049,000 for the corresponding period in 2008, a five percent increase. This increase was the result of the following factors:

- $8,447,000 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;
- $500,000 increase in various other operation and maintenance expenses; and was partially offset by
- $2,653,000 decrease in materials and parts costs as a result of cost control measures; and
- $1,189,000 decrease in property tax related to the contribution of RIGS to HPC.

General and Administrative. General and administrative expense increased to $43,331,000 in the nine months ended September 30, 2009 from $38,784,000 for the same period in 2008, a 12 percent increase. This increase is the result of the following factors:

- $2,691,000 increase in employee-related expenses due to increased employer benefits payments and bonus accrual;
- $1,110,000 increase in professional and consulting service fees; and
- $746,000 increase in various general and administrative expenses.

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

Depreciation and Amortization. Depreciation and amortization expense increased to $81,134,000 in the nine months ended September 30, 2009 from $74,638,000 for the nine months ended September 30, 2008, a nine percent increase. The following factors contributed to this increase:

- $14,487,000 increase related to various organic growth projects completed since September 30, 2008; partially offset by
- $7,991,000 decrease in depreciation expense related to the contribution of RIGS to HPC.

Interest Expense, Net. Interest expense, net increased by $7,707,000, or 16 percent, in the nine months ended September 30, 2009 compared to the same period in 2008. Interest expense, net increased by $7,192,000 due to increased levels of borrowings and $515,000 due to higher interest rates.

HPC

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

We own a 43 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 September 30, 2009 with the results of RIGS for the three months ended September 30, 2008. The following table contains key performance indicators related to our discussion of the results of operations.

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Change	Percent
	(in thousands except percentages and volume data)			
Revenues	$ 14,188	$ 16,863	$ (2,675	16 %
Cost of sales	653	196	457	233
HPC margin (1)	13,535	16,667	(3,132)	19
Operation and maintenance	2,563	(1,007)	3,570	355
General and administrative	1,766	-	1,766	N/M
Gain on asset sales, net	(13)	-	(13)	N/M
Depreciation and amortization	733	3,506	(2,773	79
Operating income	8,486	14,168	(5,682)	40
Interest expense	(65)	-	(65)	N/M
Other income and deductions, net	597	11	586	5,327
Net income	$ 9,018	$ 14,179	$ (5,161)	36 %
System inlet volumes (MMbtu/d)	735,565	795,104	(59,539)	7

N/M – not meaningful

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

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008
	(in thousands)	
Net income	$ 9,018	$ 14,179
Add (deduct):		
Operation and maintenance	2,563	(1,007)
General and administrative	1,766	-
Gain on asset sales, net	(13)	-

Depreciation and amortization		733			3,506	
Interest expense		65			-	
Other income and deductions, net		(597	)		(11	)
HPC margin	$	13,535		$	16,667	

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Net income for the three months ended September 30, 2009 was $9,018,000 compared to $14,179,000 in the three months ended September 30, 2008, a 36 percent decrease. The decrease in net income was primarily attributable to the following:

- a decrease in HPC margin of $3,132,000 due to a decrease in natural gas prices and volumes in the three months ended September 30, 2009 compared to the same period in 2008;
- an increase in operation and maintenance expense of $3,570,000 mainly resulting from increased contractor expense related to compression operations and the absence in 2009 of $3,134,000 in insurance reimbursement related to a compressor fire;
- an increase in general and administrative expenses of $1,766,000 primarily due to the recording of a management fee paid to the Partnership; and were partially offset by
- a decrease in depreciation and amortization expense of $2,773,000 due to a one-time adjustment of $3,117,000 as a result of the initial valuation of HPC's assets; and
- an increase in other income and deductions of $586,000 primarily from interest earned on the cash contributions by EFS Haynesville and Alinda Investors.

Nine Months Ended September 30, 2009 vs. Nine Months Ended September 30, 2008

We own a 43 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 September 30, 2009 to compare to RIGS' results of operations for the nine months ended September 30, 2008. The following table contains key performance indicators related to our discussion of the results of operations.

	Nine Months Ended September 30, 2009	September 30, 2008	Change	Percent
	(in thousands except percentages and volume data)			
Revenues	$ 43,341	$ 51,889	$ (8,548)	16 %
Cost of sales	3,447	985	2,462	250
HPC margin (1)	39,894	50,904	(11,010)	22
Operation and maintenance	7,844	1,833	6,011	328
General and administrative	3,689	-	3,689	N/M
Loss on asset sales, net	116	44	72	164
Depreciation and amortization	8,293	10,439	(2,146)	21
Operating income	19,952	38,588	(18,636)	48
Interest expense	(65)	-	(65)	N/M
Other income and deductions, net	1,210	11	1,199	10,900
Net income	$ 21,097	$ 38,599	$ (17,502)	45 %
System inlet volumes (MMbtu/d)	763,588	773,562	(9,974)	1

N/M – not meaningful

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

	Nine Months Ended September 30, 2009	September 30, 2008
	(in thousands)	
Net income	$ 21,097	$ 38,599

Add (deduct):				
Operation and maintenance		7,844		1,833
General and administrative		3,689		-
Loss on asset sales, net		116		44
Depreciation and amortization		8,293		10,439
Interest expense		65		-
Other income and deductions, net		(1,210)		(11)
HPC margin	$	39,894	$	50,904

Net income for the nine months ended September 30, 2009 was $21,097,000 compared to $38,599,000 in the nine months ended September 30, 2008, a 45 percent decrease. The decrease in net income was primarily attributable to the following:

- a decrease in HPC margin of $11,010,000 primarily due to the decrease in natural gas prices and volumes in 2009 compared to those in 2008;
- an increase in operation and maintenance expense of $6,011,000 mainly resulting from increased contractor expense related to compression operation and the absence in 2009 of $3,134,000 in insurance reimbursement related to a compressor fire;
- an increase in general and administrative expense of $3,689,000 primarily due to the recording of a management fee paid to the Partnership; and were partially offset by
- a decrease in depreciation and amortization expense of $2,146,000 due to a one-time adjustment of $3,117,000 as a result of the initial valuation of HPC's assets; and
- an increase in other income and deductions of $1,199,000 primarily from interest earned on the cash contributions by EFS Haynesville and Alinda Investors.

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

	Three Months Ended		Nine Months Ended	
	September 30, 2009	September 30, 2008	September 30, 2009	September 30, 2008
	(in thousands)			
Net income	$ 9,018	$ 14,179	$ 21,097	$ 38,599
Add:				
Depreciation and amortization	733	3,506	8,293	10,439
Interest expense	65	-	65	-
EBITDA	$ 9,816	$ 17,685	$ 29,455	$ 49,038

Cash Distributions. On October 21, 2009, the HPC management committee declared a distribution of $9,459,000, which was paid on October 30, 2009, of which the Partnership received its pro-rata share of $3,738,000.

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.

On September 14, 2009, HPC announced plans to construct a $47,000,000 pipeline extension of the Haynesville Expansion Project. This extension, which is called the Red River Lateral, will add approximately 100,000 MMbtu/d of capacity to the Haynesville Expansion Project, bringing the total project capacity to approximately 1.2 Bcf/d. Substantially all of the incremental capacity on the Red River Lateral has been contracted to third parties.

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 is 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 expenditures and working capital needs. Global financial markets and economic conditions continue to recover somewhat from the distressed condition of last fall and earlier this year.

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 October 31, 2009 was $268,612,000, 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.

At September 30, 2009, we have purchase obligations totaling $10,015,000 for the purchase of major compression components that extend through December 31, 2009.

In the future, HPC may request that we make additional capital contributions to support their capital expenditures and we may encounter difficulty in financing the capital contributions. 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.

We expect our growth capital expenditures to be approximately $148,800,000 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 $148,800,000 include $83,800,000 for additional compression for our contract compression segment and $65,000,000 for the expansion of our gathering and processing facilities. Our growth capital expenditures related to HPC are approximately $20,400,000 which represents our proportionate share.

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.

Working Capital Surplus. 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 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 expenditures and obligations 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 $6,854,000 from December 31, 2008 to September 30, 2009, primarily due to:

- a net increase in receivables and payables and accrued liabilities of $24,908,000 due primarily to the timing of cash receipts and disbursements;
- a net increase in cash and cash equivalent of $11,501,000; and were partially offset by
- a net increase in other liabilities of $14,149,000 primarily due to increase in interest payable associated with our senior notes;
- a net decrease in derivative assets and liabilities of $9,449,000 primarily due to an increases in commodity prices compared to December 31, 2008 levels and more favorable prices for newly entered contracts; and
- a net decrease in other assets of $5,957,000 primarily due to the amortization of prepaid insurance.

Cash Flows from Operations. Net cash flows provided by operating activities decreased $42,167,000, or 28 percent, for the nine months ended September 30, 2009 as compared to the same period in 2008, primarily due to lower commodity prices and a small 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 were $126,786,000 in the nine months ended September 30, 2009 compared to $817,026,000 in the nine months ended September 30, 2008. The net cash flows used in investing activities in the nine months ended September 30, 2008 were 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 nine months ended September 30, 2009, we incurred $104,155,000 for growth projects exclusive of growth capital expenditures related to the Haynesville Expansion Project. The expenditures were primarily comprised of $74,587,000 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 nine months ended September 30, 2009, we incurred $15,410,000 of maintenance capital expenditures. Maintenance capital expenditures primarily consisted of compressor and equipment overhauls.

Cash Flows from Financing Activities. Net cash flows provided by financing activities were $31,174,000 in the nine months ended September 30, 2009 compared to $649,594,000 in the same period in 2008. In the nine months ended September 30, 2009, cash flows provided by financing activities related primarily to proceeds from issuance of senior notes as well as Convertible Redeemable Preferred Units, partially offset by distributions to unitholders and repayments of revolving credit facilities. In the nine months ended September 30, 2008, cash flows provided by financing activities were primarily associated with borrowings for our FrontStreet, CDM and Nexus acquisitions.

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

	Moody's	Standard & Poor's
Regency Energy Partners LP		
Outlook	Negative	Negative
Senior notes 8.375 due 2013	B1	B
Senior notes 9.375 due 2016	B1	B
Corporate rating/total debt	Ba3	BB-

40

Capital Resources

Senior Notes. On May 20, 2009, the Partnership and Finance Corp. issued $250,000,000 senior notes in a private placement that matures 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.

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. Beginning June 1, 2013, we may redeem all or part of the notes for the principle amount plus a declining premium until June 1, 2015, and thereafter at par, plus accrued and unpaid interest. 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 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 a change of control, each noteholder 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. 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.

Convertible Redeemable Preferred Units. On September 2, 2009, we issued 4,371,586 Convertible Redeemable Preferred Units at a price of $18.30 per unit, less a four percent discount of $3,200,000, for net proceeds of $76,800,000. The Convertible Redeemable Preferred Units are convertible to common units under terms described below, and if outstanding, are redeemable on September 2, 2029. The Convertible Redeemable Preferred Units will receive fixed quarterly cash distributions of $0.445 per unit beginning with the quarter ending March 31, 2010.

Distributions on the Convertible Redeemable Preferred Units will be accrued for the quarters ending September 30, 2009 and December 31, 2009 (and not paid in cash) and will result in an increase in the number of common units issuable upon conversion. If on any distribution payment date beginning March 31, 2010, we (1) fail to pay distributions on the Convertible Redeemable Preferred Units, (2) reduce the distributions on the common units to zero and (3) are prohibited by our material financing agreements from paying cash distributions, such distributions shall automatically accrue and accumulate until paid in cash. If we have failed to pay cash distributions in full for two quarters (whether or not consecutive) from and including the quarter ending on March 31, 2010, then if we fail to pay cash distributions on the Convertible Redeemable Preferred Units, all future distributions on the Convertible Redeemable Preferred Units that are accrued rather than being paid in cash by us will consist of the following: (1) $0.35375 per Convertible Redeemable Preferred Unit per quarter, (2) $0.09125 per Convertible Redeemable Preferred Unit per quarter (the “Common Unit Distribution Amount”), payable solely in common units, and (3) $0.09125 per Convertible Redeemable Preferred Unit per quarter (the “PIK Distribution Additional Amount”), payable solely in common units. The total number of common units payable in connection with the Common Unit Additional Amount or the PIK Distribution Additional Amount cannot exceed 1,600,000 in any period of twenty consecutive fiscal quarters.

Upon our breach of certain covenants related to the 9.375 Senior Notes due 2016 (a "Covenant Default"), the holders of the Convertible Redeemable Preferred Units will be entitled to an increase of $0.1825 per quarterly distribution, payable solely in common units (the "Covenant Default Additional Amount"). All accumulated and unpaid distributions will accrue interest (i) at a rate of 2.432 percent per quarter, or (ii) if we have failed to pay all PIK Distribution Additional Amounts or Covenant Default Additional Amounts or any Covenant Default has occurred and is continuing, at a rate of 3.429 percent per quarter while such failure to pay or such Covenant Default continues.

The Convertible Redeemable Preferred Units are convertible, at the holder's option, into common units commencing on March 2, 2010, provided that the holder must request conversion of at least 375,000 Convertible Redeemable Preferred Units. The conversion price will initially be $18.30, subject to adjustment for customary events (such as unit splits) and until December 31, 2011, based on a weighted average formula in the event that we issue any common units (or securities convertible or exercisable into common units) at a per Common Unit price below $16.47 per common unit. The number of common units issuable is equal to the issue price of the Convertible Redeemable Preferred Units (i.e. $18.30) being converted plus all accrued but unpaid distributions and accrued but unpaid interest thereon (the "Redeemable Face Amount"), divided by the applicable conversion price.

Commencing on September 2, 2014, if at any time the volume-weighted average trading price of the common units over the trailing 20-trading day period (the "VWAP Price") is less than the then-applicable conversion price, the conversion ratio will be increased to: the quotient of (1) the Redeemable Face Amount on the date that the holder's conversion notice is delivered, divided by (2) the product of (x) the VWAP Price set forth in the applicable conversion notice and (y) 91 percent, but will not be less than $10.

Also commencing on September 2, 2014, we will have the right at any time to convert all or part of the Convertible Redeemable Preferred Units into common units, if (1) the daily volume-weighted average trading price of the common units is greater than 150 percent of the then-applicable conversion price for twenty (20) out of the trailing thirty (30) trading days, and (2) certain minimum public float and trading volume requirements are satisfied.

The Convertible Redeemable Preferred Units are mandatorily redeemable on September 2, 2029 for $80,000,000 plus all accrued but unpaid distributions thereon (the "Series A Liquidation Value").

In the event of a change of control followed by a ratings decline, we will be required to make an offer to the holders of the Convertible Redeemable Preferred Units to purchase their Convertible Redeemable Preferred Units for an amount equal to 101 percent of their Series A Liquidation Value. In addition, until and including the fifth anniversary of the issuance date, in the event of certain business combinations or other transactions involving us in which the holders of common units receive cash consideration exclusively in exchange for their common units (a "Cash Event"), we must use commercially reasonable efforts to ensure that the holders of the Convertible Redeemable Preferred Units will be entitled to receive a security issued by the surviving entity in the Cash Event with comparable powers, preferences and rights to the Convertible Redeemable Preferred Units. If we are unable to ensure that the holders of the Convertible Redeemable Preferred Units will be entitled to receive such a security, then we will be required to make an offer to the holders of the Convertible Redeemable Preferred Units to purchase their Convertible Redeemable Preferred Units for an amount equal to 120 percent of their Series A Liquidation Value. If we enter into any recapitalization, reorganization, consolidation, merger, spin-off that is not a Cash Event, we will make appropriate provisions to ensure that the holders of the Convertible Redeemable Preferred Units receive a security with comparable powers, preferences and rights to the Convertible Redeemable Preferred Units upon consummation of such transaction.

HPC Working Capital Facility. In July 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 our portion 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 September 30, 2009.

Contractual Cash Obligations		Total		2009		Payment Period 2010-2011 (in thousands)		2012-2013		Thereafter
Long-term debt (including interest) (1)	$	1,565,749	$	33,536	$	759,363	$	464,256	$	308,594
Capital leases		9,611		154		1,011		884		7,562
Operating leases		26,501		1,024		7,657		5,769		12,051
Purchase obligations		10,015		10,015		-		-		-
Distributions and Redemption of Convertible Redeemable Preferred Units (2)		235,628		-		13,617		15,563		206,448
Total (3) (4)	$	1,847,504	$	44,729	$	781,648	$	486,472	$	534,655

(1) Assumes a constant LIBOR interest rate of 1.26 percent plus the applicable margin (3 percent as of September 30, 2009) for our revolving credit facility. The principal of our two issues of outstanding senior notes ($357,500,000 and $250,000,000) bears a fixed interest rate of 8.375 percent and 9.375, respectively.
(2) Assumes that the Convertible Redeemable Preferred Units are redeemed for cash on September 2, 2029.
(3) 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.
(4) Excludes deferred tax liabilities of $8,221,000 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:

	2009	2010	2011
NGL	99%	56%	18%
Condensate	76%	76%	18%
Natural gas	86%	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"), interest rate swaps outstanding at September 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)
October 2009-June 2010	Ethane	531	(MBbls)	Index	$ 0.404-$0.8	($/gallon)	$ 849
October 2009-December 2010	Propane	469	(MBbls)	Index	$ 0.875-$01.5325	($/gallon)	6,759
October 2009-December 2010	Iso Butane	91	(MBbls)	Index	$ 1.685-$1.915	($/gallon)	2,219
October 2009-December 2010	Normal Butane	220	(MBbls)	Index	$ 1.115-$1.895	($/gallon)	2,990
October 2009-June 2011	Natural Gasoline	188	(MBbls)	Index	$ 1.4975-$1.555	($/gallon)	5,283
October 2009-June 2011	West Texas Intermediate Crude	355	(MBbls)	Index	$ 68.17-$121.3	($/Bbl)	10,986
October 2009-December 2010	Natural Gas	2,745,000	(MMBtu)	Index	$ 2.53-$6.894	($/MMBtu)	1,428
October 2009-December 2010	Interest Rate	$ 300,000,000		2.40%	One-month	LIBOR	(2,677)
Credit risk adjustment							(100)

Total Fair Value	$ 27,737

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 our forecasted NGLs and condensate equity exposure for the first half of 2011. These swaps are accounted for using mark-to-market accounting treatment.

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 September 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

The information required for this item is provided in Note 1, Organization and Summary of Significant Accounting Policies, Note 8, Convertible Redeemable Preferred Units, included in the notes to the unaudited condensed financial statements included under Part I, Item 1, which information is incorporated by reference into this item.

Item 6. Exhibits

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

Exhibit 10.1 – Consulting agreement with Randall Dean
Exhibit 10.2 – Employment agreement with David Marrs
Exhibit 10.3 – Severance agreement with Paul Jolas
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

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

REGENCY ENERGY PARTNERS LP
By: Regency GP LP, its general partner
By: Regency GP LLC, its general partner

Date: November 6, 2009

/s/ Lawrence B. Connors
Lawrence B. Connors
Senior Vice-President and Chief Accounting Officer
(Duly Authorized Officer)