Regency Energy Partners LP
Form 10-Q
May 07, 2010

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2010

OR

¨ **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. x Yes ¨ No

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). ¨ Yes ¨ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and small reporting company in Rule 12b-2 of the Exchange Act.

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

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

The issuer had 93,191,602 common units outstanding as of April 30, 2010.

Introductory Statement

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

Name	Definition or Description
Bcf/d	One billion cubic feet per day
EFS Haynesville	EFS Haynesville, LLC, a 100 percent owned subsidiary of GECC
El Paso	El Paso Field Services, LP
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Finance Corp.	Regency Energy Finance Corp., a wholly-owned subsidiary of the Partnership
GAAP	Accounting principles generally accepted in the United States
GE	General Electric Company
GECC	General Electric Capital Corporation, an indirect wholly owned subsidiary of GE
GE EFS	General Electric Energy Financial Services, a unit of GECC, combined with Regency GP Acquirer LP and Regency LP Acquirer LP
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 RIG
LIBOR	London Interbank Offered Rate
LTIP	Long-Term Incentive Plan
MMbtu/d	One million BTUs per day
MMcf	One million cubic feet
MMcf/d	One million cubic feet per day
NYMEX	New York Mercantile Exchange
Partnership	Regency Energy Partners LP
RFS	Regency Field Services LLC, a wholly-owned subsidiary of the Partnership
RGS	Regency Gas Services LP, a wholly-owned subsidiary of the Partnership
RIG	Regency Intrastate Gas LP, a wholly-owned subsidiary of HPC, which was converted from Regency Intrastate Gas LLC upon HPC formation
RIGS	Regency Intrastate Gas System
SEC	Securities and Exchange Commission
TCEQ	Texas Commission on Environmental Quality
WTI	West Texas Intermediate Crude

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, as amended (the Securities Act) and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act). 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 expressions help identify forward-look
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;
- regulation of transportation rates on our natural gas pipelines;
- 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, 2009 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.

Regency Energy Partners LP

Condensed Consolidated Balance Sheets

(in thousands except unit data)

	March 31, 2010 (unaudited)	December 31, 2009
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 4,086	$ 9,827
Restricted cash	1,511	1,511
Trade accounts receivable, net of allowance of $435 and $1,130	24,655	30,433
Accrued revenues	96,584	95,240
Related party receivables	3,416	6,222
Derivative assets	22,708	24,987
Other current assets	9,930	10,556
Total current assets	162,890	178,776
Property, Plant and Equipment:		
Gathering and transmission systems	470,275	465,959
Compression equipment	835,037	823,060
Gas plants and buildings	159,795	159,596
Other property, plant and equipment	167,562	162,433
Construction-in-progress	104,071	95,547
Total property, plant and equipment	1,736,740	1,706,595
Less accumulated depreciation	(272,104)	(250,160)
Property, plant and equipment, net	1,464,636	1,456,435
Other Assets:		
Investment in unconsolidated subsidiary	477,717	453,120
Long-term derivative assets	799	207
Other, net of accumulated amortization of debt issuance costs of $4,631 and $10,743	35,294	19,468
Total other assets	513,810	472,795
Intangible Assets and Goodwill:		
Intangible assets, net of accumulated amortization of $37,126 and $33,929	194,097	197,294
Goodwill	228,114	228,114
Total intangible assets and goodwill	422,211	425,408
TOTAL ASSETS	$ 2,563,547	$ 2,533,414
LIABILITIES & PARTNERS CAPITAL AND NONCONTROLLING INTEREST		
Current Liabilities:		
Trade accounts payable	$ 36,161	$ 44,912
Accrued cost of gas and liquids	73,233	76,657
Related party payables	927	2,312
Deferred revenues, including related party amounts of $0 and $338	10,795	11,292
Derivative liabilities	5,317	12,256
Escrow payable	1,511	1,511
Other current liabilities	24,499	12,368
Total current liabilities	152,443	161,308

Long-term derivative liabilities	48,843	48,903
Other long-term liabilities	14,546	14,183
Long-term debt, net	1,083,665	1,014,299
Commitments and contingencies		
Series A convertible redeemable preferred units, redemption amount of $83,891 and $83,891	51,766	51,711
Partners Capital and Noncontrolling Interest:		
Common units (94,271,956 and 94,243,886 units authorized; 93,197,173 and 93,188,353 units issued and outstanding at March 31, 2010 and December 31, 2009)	1,170,270	1,211,605
General partner interest	18,337	19,249
Accumulated other comprehensive gain (loss)	10,500	(1,994)
Noncontrolling interest	13,177	14,150
Total partners capital and noncontrolling interest	1,212,284	1,243,010
TOTAL LIABILITIES AND PARTNERS CAPITAL AND NONCONTROLLING INTEREST	$ 2,563,547	$ 2,533,414

See accompanying notes to condensed consolidated financial statements

Regency Energy Partners LP

Condensed Consolidated Statements of Operations

Unaudited

(in thousands except unit data and per unit data)

	Three Months Ended March 31, 2010	2009
REVENUES		
Gas sales	$ 142,893	$ 148,270
NGL sales	97,329	49,585
Gathering, transportation and other fees, including related party amounts of $8,520 and $811	70,328	72,621
Net realized and unrealized (loss) gain from derivatives	(939)	14,455
Other	8,141	5,194
Total revenues	317,752	290,125
OPERATING COSTS AND EXPENSES		
Cost of sales, including related party amounts of $3,366 and $247	224,609	182,901
Operation and maintenance	32,411	36,042
General and administrative	15,403	14,852
Loss (gain) on asset sales, net	284	(133,932)
Depreciation and amortization	27,475	27,889
Total operating costs and expenses	300,182	127,752
OPERATING INCOME	17,570	162,373
Income from unconsolidated subsidiary	7,913	336
Interest expense, net	(22,345)	(14,227)
Other income and deductions, net	(3,267)	42
(LOSS) INCOME BEFORE INCOME TAXES	(129)	148,524
Income tax expense	321	100
NET (LOSS) INCOME	(450)	148,424
Net income attributable to noncontrolling interest	(162)	(35)
NET (LOSS) INCOME ATTRIBUTABLE TO REGENCY ENERGY PARTNERS LP	$ (612)	$ 148,389
Amounts attributable to Series A convertible redeemable preferred units	2,001	
General partner s interest, including IDR	662	3,533
Amount allocated to non-vested common units	(79)	1,354
Beneficial conversion feature for Class D common units		820
Limited partners interest	$ (3,196)	$ 142,682
Basic and Diluted (loss) earnings per unit:		
Amount allocated to common units	$ (3,196)	$ 142,682
Weighted average number of common units outstanding	92,761,787	77,271,886
Basic (loss) income per common unit	$ (0.03)	$ 1.85
Diluted (loss) income per common unit	$ (0.03)	$ 1.78
Distributions paid per unit	$ 0.445	$ 0.445
Amount allocated to Class D common units	$	$ 820
Total number of Class D common units outstanding		7,276,506

Income per Class D common unit due to beneficial conversion feature	$		$	0.11
Distributions per unit	$		$	

See accompanying notes to condensed consolidated financial statements

Regency Energy Partners LP

Condensed Consolidated Statements of Comprehensive Income

Unaudited

(in thousands)

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Net (loss) income	$ (450)	$ 148,424
Net hedging amounts reclassified to earnings	2,657	(14,250)
Net change in fair value of cash flow hedges	9,837	5,380
Comprehensive income	$ 12,044	$ 139,554
Comprehensive income attributable to noncontrolling interest	162	35
Comprehensive income attributable to Regency Energy Partners LP	$ 11,882	$ 139,519

See accompanying notes to condensed consolidated financial statements

Regency Energy Partners LP

Condensed Consolidated Statements of Cash Flows

Unaudited

(in thousands)

	Three Months Ended March 31, 2010	2009
OPERATING ACTIVITIES		
Net (loss) income	$ (450)	$ 148,424
Adjustments to reconcile net (loss) income to net cash flows provided by operating activities:		
Depreciation and amortization, including debt issuance cost amortization	29,389	28,932
Write-off of debt issuance costs	1,780	
Income from unconsolidated subsidiary	(7,913)	(336)
Derivative valuation changes	7,182	(3,565)
Loss (gain) on asset sales, net	284	(133,932)
Unit-based compensation expenses	1,639	1,189
Cash flow changes in current assets and liabilities:		
Trade accounts receivable, accrued revenues, and related party receivables	(2,017)	22,741
Other current assets	1,091	10,458
Trade accounts payable, accrued cost of gas and liquids, and related party payables	(13,826)	(36,948)
Other current liabilities	12,131	(1,022)
Distribution received from unconsolidated subsidiary	3,526	
Other assets and liabilities	(35)	390
Net cash flows provided by operating activities	32,781	36,331
INVESTING ACTIVITIES		
Capital expenditures	(38,465)	(80,255)
Capital contribution to unconsolidated subsidiary	(20,210)	
Proceeds from asset sales	10,632	83,097
Net cash flows (used in) provided by investing activities	(48,043)	2,842
FINANCING ACTIVITIES		
Net borrowings under revolving credit facility	69,009	7,004
Debt issuance costs	(15,272)	(6,055)
Partner distributions	(43,034)	(34,143)
Distributions to noncontrolling interest	(1,135)	
Equity issuance costs	(47)	
Net cash flows provided by (used in) financing activities	9,521	(33,194)
Net (decrease) increase in cash and cash equivalents	(5,741)	5,979
Cash and cash equivalents at beginning of period	9,827	599
Cash and cash equivalents at end of period	$ 4,086	$ 6,578
Supplemental cash flow information:		
Non-cash capital expenditures	$ 9,936	$ 18,241
Contribution of fixed assets, intangible assets, goodwill and working capital to HPC		263,921

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	Common Unitholders	General Partner Interest	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance - December 31, 2009	93,188,353	$ 1,211,605	$ 19,249	$ (1,994)	$ 14,150	$ 1,243,010
Issuance of common units under LTIP, net of forfeitures	8,820					
Issuance of common units, net of costs		(47)				(47)
Unit-based compensation expenses		1,639				1,639
Accrued distributions to phantom units		(138)				(138)
Partner distributions		(41,460)	(1,574)			(43,034)
Distributions to noncontrolling interest					(1,135)	(1,135)
Net (loss) income		(1,274)	662		162	(450)
Accretion of Series A convertible redeemable preferred units		(55)				(55)
Net cash flow hedge amounts reclassified to earnings				2,657		2,657
Net change in fair value of cash flow hedges				9,837		9,837
Balance - March 31, 2010	93,197,173	$ 1,170,270	$ 18,337	$ 10,500	$ 13,177	$ 1,212,284

See accompanying notes to condensed consolidated financial statements

Regency Energy Partners LP

Notes to Unaudited Condensed Consolidated Financial Statements

1. Organization and Summary of Significant Accounting Policies

Organization. The unaudited condensed consolidated financial statements presented herein contain the results of Regency Energy Partners LP (the Partnership) and its subsidiaries. The Partnership and its subsidiaries are engaged in the business of gathering, processing and transporting of natural gas and NGLs as well as providing contract compression services.

The unaudited financial information as of, and for the three months ended March 31, 2010, 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, 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 inter-company items and transactions have been eliminated in consolidation. Certain information and footnote disclosures normally included in annual consolidated financial statements prepared in accordance with GAAP have been omitted pursuant to the rules and regulations of the SEC.

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

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

	Contracts	Customer Relations	Trade Names	Permits and Licenses	Total
			(in thousands)		
Balance at December 31, 2009	$ 126,332	$ 35,362	$ 30,508	$ 5,092	$ 197,294
Amortization	(1,994)	(490)	(585)	(128)	(3,197)
Balance at March 31, 2010	$ 124,338	$ 34,872	$ 29,923	$ 4,964	$ 194,097

The expected amortization of the intangible assets for each of the five succeeding years is as follows.

Year ending December 31,	Total (in thousands)
2010 (remaining)	$ 9,589
2011	11,477
2012	11,235
2013	11,235
2014	11,235

Recently Issued Accounting Standards. In June 2009, the FASB issued guidance that significantly changed 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 determined that this guidance had no impact on its financial position, results of operations or cash flows upon adoption on January 1, 2010.

In January 2010, the FASB issued guidance requiring improved disclosure of transfers in and out of Levels 1 and 2 for an entity s fair value measurements, such requirement becoming effective for interim and annual periods beginning after December 15, 2009. Further, additional disclosure of activities such as purchases, sales, issuances and settlements of items relying on Level 3 inputs will be required, such requirements becoming effective for interim and annual periods beginning after December 15, 2010. The Partnership determined that this guidance with respect to Levels 1, 2 and 3 had no impact on its financial position, results of operations or cash flows upon adoption.

In February 2010, the FASB clarified the type of embedded credit derivative that is exempt from embedded derivative bifurcation requirements. The Partnership evaluated the impact of this update on its accounting for embedded derivatives and determined that it had no impact on its financial position, results of operations or cash flows.

2. Income per Limited Partner Unit

On September 2, 2009, the Partnership issued 4,371,586 Series A Convertible Redeemable Preferred Units (Series A Preferred Units). The Series A 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 ended September 30, 2009 and December 31, 2009 were accrued, effectively increasing the conversion value of the Series A 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 Series A Preferred Units, are treated as a reduction in net income available to the general partner and limited partner interests.

Regency Energy Partners LP

Notes to Unaudited Condensed Consolidated Financial Statements (Continued)

The following table provides a reconciliation of the numerator and denominator of the basic and diluted earnings per common unit computations for the three months ended March 31, 2010 and 2009.

	For the Three Months Ended March 31, 2010			For the Three Months Ended March 31, 2009		
	Loss (Numerator)	Units (Denominator)	Per-Unit Amount	Income (Numerator)	Units (Denominator)	Per-Unit Amount
	(in thousands except unit and per unit data)					
Basic Earnings per Unit						
Limited partners interest	$ (3,196)	92,761,787	$ (0.03)	$ 142,682	77,271,886	$ 1.85
Effect of Dilutive Securities						
Class D common units				820	3,234,003	
Diluted Earnings per Unit	$ (3,196)	92,761,787	$ (0.03)	$ 143,502	80,505,889	$ 1.78

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

	Three Months Ended March 31, 2010	2009
Non-vested common units	421,072	699,175
Phantom units*	383,706	
Common unit options	306,651	328,618
Series A Preferred Units	4,371,586	

* Amount disclosed assumes maximum conversion rate for market condition awards.

3. Investment in Unconsolidated Subsidiary

HPC was established in March 2009 and as of March 31, 2010, the Partnership owns a 43 percent partner s interest in HPC. In February 2010, the Partnership made an additional capital contribution of $20,210,000 to HPC. The Partnership recognized $7,913,000 and $336,000 during the quarters ended March 31, 2010 and 2009, respectively, in income from unconsolidated subsidiary for its ownership interest. In addition, the Partnership received $3,526,000 of distributions during the quarter ended March 31, 2010. The summarized financial information of HPC is disclosed below.

RIGS Haynesville Partnership Co.

Condensed Consolidated Balance Sheets

(in thousands)

	March 31, 2010 (Unaudited)	December 31, 2009
ASSETS		
Total current assets	$ 44,033	$ 39,239
Restricted cash, non-current	55,610	33,595

Property, plant and equipment, net		884,774		861,570
Total other assets		149,324		149,755
TOTAL ASSETS	$	1,133,741	$	1,084,159
LIABILITIES & PARTNERS CAPITAL				
Total current liabilities	$	19,346	$	30,967
Long-term debt		4,000		
Partners capital		1,110,395		1,053,192
TOTAL LIABILITIES & PARTNERS CAPITAL	$	1,133,741	$	1,084,159

Regency Energy Partners LP

Notes to Unaudited Condensed Consolidated Financial Statements (Continued)

RIGS Haynesville Partnership Co.

Condensed Consolidated Income Statements

(in thousands)

	For the Three Months Ended March 31, 2010	March 31, 2009
	(Unaudited)	
Total revenues	$ 35,189	$ 1,826
Total operating costs and expenses	16,723	1,046
OPERATING INCOME	18,466	780
Interest expense	(102)	
Other income and deductions, net	39	104
NET INCOME	$ 18,403	$ 884

4. Derivative Instruments

Policies. The Partnership has established comprehensive risk management policies and procedures to monitor and manage the market risks associated with commodity prices, counterparty credit, and interest rates. The 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.

Commodity Price Risk. The Partnership is a net seller of NGLs, condensate and natural gas as a result of its gathering and processing operation. The prices of these commodities are impacted by changes in the supply and demand as well as market focus. Both the Partnership s profitability and cash flow are affected by the inherent volatility of these commodities which could adversely affect its ability to make distributions to its 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. 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. It is the Partnership s policy not to take any speculative positions with its derivative contracts.

On April 5, 2010, the Partnership entered into additional NGLs swaps to hedge a portion of its 2011 NGLs sales.

The Partnership has executed swap contracts settled against NGLs (ethane, propane, butane and natural gasoline), condensate and natural gas market prices for expected equity exposure in the approximate percentages set for below.

	As of March 31, 2010		As of April 5, 2010	
	2010	2011	2010	2011
NGLs	73%	29%	73%	41%
Condensate	84%	50%	84%	50%
Natural gas	74%	23%	74%	23%

At March 31, 2010, the 2010 and 2011 natural gas and condensate swaps are accounted for as cash flow hedges with the exception of one month of the 2010 condensate swaps, which is accounted for using the mark-to-market accounting; the 2010 NGLs swaps are accounted for using a combination of cash flow hedge and mark-to-market accounting and the 2011 NGLs swaps are accounted for as cash flow hedges.

Interest Rate Risk. The Partnership is exposed to variable interest rate risk as a result of borrowings under its credit facility. As of March 31, 2010, the Partnership had $488,650,000 of outstanding borrowings exposed to variable interest rate risk. The Partnership s $300,000,000 interest rate swaps expired in March 2010. In April 2010, the Partnership entered into additional two-year interest rate swaps related to $250,000,000 of borrowings under its revolving credit facility, effectively locking the base rate for these borrowings at 1.325 percent through April 2012.

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 extension of credit is backed by adequate collateral such as a letter of credit or parental guarantee.

The Partnership is exposed to credit risk from its derivative counterparties. The Partnership does not require collateral from these counterparties. The Partnership deals primarily with financial institutions when entering into financial derivatives. The Partnership has entered into Master International Swap Dealers Association (ISDA) Agreements that allow for netting of swap

Regency Energy Partners LP

Notes to Unaudited Condensed Consolidated Financial Statements (Continued)

contract receivables and payables in the event of default by either party. If the Partnership s counterparties fail to perform under existing swap contracts, the Partnership s maximum loss would be $23,596,000, which would be reduced by $6,181,000 due to the netting feature. The Partnership has elected to present assets and liabilities under Master ISDA Agreements gross on the condensed consolidated balance sheets.

Embedded Derivatives. The Series A Preferred Units contain embedded derivatives which are required to be bifurcated and accounted for separately, such as the holders conversion option and the Partnership s call option. These embedded derivatives are accounted for using mark-to-market accounting. The Partnership does not expect the embedded derivatives to affect its cash flows. During the three months ended March 31, 2010, the loss recognized related to these embedded derivatives was $3,385,000 and was reflected in other income and deductions, net on the condensed consolidated statement of operations.

Quantitative Disclosures. The Partnership expects to reclassify $5,973,000 of net hedging gains to revenues from accumulated other comprehensive income (OCI) in the next 12 months.

The Partnership s derivative assets and liabilities, including credit risk adjustment, as of March 31, 2010 and December 31, 2009 and for the three months ended March 31, 2010 and 2009 are detailed below.

	Assets		Liabilities	
	March 31, 2010	December 31, 2009	March 31, 2010	December 31, 2009
	(in thousands)			
Derivatives designated as cash flow hedges				
Current amounts				
Interest rate contracts	$	$	$	$ 1,067
Commodity contracts	10,909	9,525	5,282	11,200
Long-term amounts				
Commodity contracts	799	207	864	931
Total cash flow hedging instruments	11,708	9,732	6,146	13,198
Derivatives not designated as cash flow hedges				
Current amounts				
Commodity contracts	11,888	15,514	35	31
Long-term amounts				
Commodity contracts				3,378
Embedded derivatives in Series A Preferred Units			47,979	44,594
Total derivatives not designated as cash flow hedges	11,888	15,514	48,014	48,003
Credit Risk Assessment				
Current amounts	(89)	(52)		(42)
Total derivatives	$ 23,507	$ 25,194	$ 54,160	$ 61,159

Derivatives designated as cash flow hedges

	Three Months Ended March 31, 2010			Three Months Ended March 31, 2009		
	Interest Rate	Commodity	Total	Interest Rate	Commodity	Total
			(in thousands)			
Gain (loss) recorded in accumulated OCI (Effective)	$	$ 6,943	$ 6,943	$ (838)	$ 6,218	$ 5,380
Gain (loss) reclassified from accumulated OCI into income (Effective)*	(1,060)	(4,491)	(5,551)	(1,472)	16,519	15,047
(Loss) gain recognized in income (Ineffective)*		(498)	(498)		615	615

Derivatives not designated as cash flow hedges

	Three Months Ended March 31, 2010			Three Months Ended March 31, 2009		
	Embedded Derivative	Commodity	Total	Embedded Derivative	Commodity	Total
			(in thousands)			
Gain (loss) from dedesignation amortized from accumulated OCI into income*	$	$ 2,894	$ 2,894	$	$ (797)	$ (797)
Gain (loss) gain recognized in income*	(3,385)	1,235	(2,150)		(1,402)	(1,402)

Credit risk assessment for commodity and interest rate swaps

	Three Months Ended March 31,	
	2010	2009
	(in thousands)	
Loss recognized in income*	$ (79)	$ (480)

* Gain and loss related to commodity swaps, interest rate swaps and embedded derivatives were included in revenues, interest expense, and other income and deductions, net, respectively, in the Partnership s condensed consolidated statements of operations for the three months ended March 31, 2010 and 2009.

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Notes to Unaudited Condensed Consolidated Financial Statements (Continued)

5. Long-term Debt

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

	March 31, 2010	December 31, 2009
	(in thousands)	
Senior notes	$ 595,015	$ 594,657
Revolving loans	488,650	419,642
Total	1,083,665	1,014,299
Less: current portion		
Long-term debt	$ 1,083,665	$ 1,014,299
Availability under revolving credit facility:		
Total credit facility limit	$ 900,000	$ 900,000
Unfunded commitments		(10,675)
Revolving loans	(488,650)	(419,642)
Letters of credit	(10,757)	(16,257)
Total available	$ 400,593	$ 453,426

Long-term debt maturities as of March 31, 2010 for each of the next five years are as follows:

Year Ending December 31,	Amount (in thousands)
2010	$
2011	
2012	
2013	357,500
2014	488,650
Thereafter	250,000*
Total	$ 1,096,150

* As of March 31, 2010, the carrying value of the senior notes due 2016 was $237,515,000 which included an unamortized discount of $12,485,000.

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 senior notes pay fixed interest rates and the weighted average coupon rate is 8.787 percent. 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 7.80 percent and 5.19 percent for the three months ended March 31, 2010 and 2009, respectively.

Senior Notes. 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 and the Series A Preferred Units, to the extent of the value of the assets securing such obligations. As of March 31, 2010, the Partnership was in compliance with each of the financial covenants required under the terms of the senior notes.

Finance Corp. has no operations and will not have revenues 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.

Revolving Credit Facility. On March 4, 2010, RGS executed the Fifth Amended and Restated Credit Agreement (the new credit agreement), to be effective as of March 4, 2010. The material differences between the Fourth Amended and Restated Credit Agreement (the previous credit agreement) and the new credit agreement include:

- The extension of the maturity date to June 15, 2014 from August 15, 2011, subject to the following contingency:

  - If the Partnership s 8.375 percent senior notes due December 15, 2013 have not been refinanced or paid off by June 15, 2013, then the maturity date will be June 15, 2013;

- An increase in the amount of allowed investments in HPC to $250,000,000 from $135,000,000;

- The addition of an allowance for joint venture investments (other than HPC) of up to $75,000,000, provided that (i) distributed cash and net income from joint ventures under this basket shall be excluded from consolidated net income and (ii) equity interests in joint ventures created under this basket shall be pledged as collateral;

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Notes to Unaudited Condensed Consolidated Financial Statements (Continued)

The modification of financial covenants to give credit for projected EBITDA associated with certain future material HPC projects on a percentage of completion basis, provided that such amount, together with adjustments related to the Haynesville Expansion Project and other material projects, does not exceed 20 percent of consolidated EBITDA (as defined in the new credit agreement) through March 31, 2010, and 15 percent thereafter;

An increase in the annual general asset sales permitted from $20,000,000 annually to five percent of consolidated net tangible assets (as defined in the new credit agreement) annually.

The new credit agreement and the guarantees are senior to the Partnership s and the guarantors secured obligations, including the Series A Preferred Units, to the extent of the value of the assets securing such obligations. As of March 31, 2010, the Partnership was in compliance with all of the financial covenants contained within the new credit agreement.

The Partnership treated the amendment of the credit facility as a modification of an existing revolving credit agreement and, therefore, recorded a write-off of debt issuance costs of $1,780,000 that was recorded to interest expense, net in the three months ended March 31, 2010. In addition, the Partnership paid and capitalized $15,272,000 loan fees which will be amortized over the remaining term of the credit facility.

6. Commitments and Contingencies

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

Escrow Payable. At March 31, 2010, $1,511,000 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 and a subsequent 2008 settlement agreement between the Partnership and El Paso. In the El Paso PSA, El Paso indemnified Regency Gas Services LLC, now known as Regency Gas Services LP, 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. In connection with this matter, $500,000 was released on May 6, 2010.

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.

Keyes Litigation. In August 2008, Keyes Helium Company, LLC (Keyes) filed suit against Regency Gas Services LP, the Partnership, the General Partner and various other subsidiaries. Keyes entered into an output contract with the Partnership s predecessor-in-interest 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 its suit, Keyes alleges it is entitled to damages for the costs of covering its purchases of helium. Discovery ended in October 2009. Trial commenced on April 26, 2010.

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 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 advised the Partnership that a portion of its condensate sales in Kansas is subject to severance tax; therefore the Partnership will be subject to additional taxes on future condensate sales. The Partnership may also be subject to additional taxes, interest and possible penalties for past condensate sales.

Remediation of Groundwater Contamination at Calhoun and Dubach Plants. Regency Field Services LLC (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 Field Services LP (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

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Notes to Unaudited Condensed Consolidated Financial Statements (Continued)

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 Plants. RFS is seeking assignment of indemnity rights against Tronox from El Paso.

7. Series A Convertible Redeemable Preferred Units

On September 2, 2009, the Partnership issued 4,371,586 Series A Preferred Units. As of March 31, 2010, the Series A Preferred Units were convertible to 4,584,192 common units, and if outstanding, are mandatorily redeemable on September 2, 2029 for $80,000,000 plus all accrued but unpaid distributions thereon. The Series A Preferred Units will receive fixed quarterly cash distributions of $0.445 per unit beginning with the quarter ending March 31, 2010, if outstanding on the record dates of the Partnership s common units distributions. Effective as of March 2, 2010, holders can elect to convert Series A Preferred Units to common units at any time in accordance with the partnership agreement.

The following table provides a reconciliation of the beginning and ending balances of the Series A Preferred Units for the three months ended March 31, 2010.

	For the Three Months Ended March 31, 2010	
	Units	**Amount (in thousands)**
Beginning balance as of January 1, 2010	4,371,586	$ 51,711
Accretion to redemption value		55
Ending balance as of March 31, 2010	4,371,586	$ 51,766*

* This amount will be accreted to $80,000,000 plus any accrued and unpaid distributions by deducting amounts from partners capital over the 19.5 remaining years.

8. Related Party Transactions

The employees operating the assets of the Partnership and its subsidiaries and all those providing staff or support services are employees of the General Partner. Pursuant to the Partnership Agreement, the General Partner receives a monthly reimbursement for all direct and indirect expenses incurred on behalf of the Partnership. Reimbursements of $20,732,000, and $7,808,000, were recorded in the Partnership s financial statements during the three months ended March 31, 2010 and 2009, respectively, as operating expenses or general and administrative expenses, as appropriate.

In conjunction with distributions by the Partnership to its limited and general partner interests, GE EFS received cash distributions of $13,127,000 and $9,578,000 during the three months ended March 31, 2010 and 2009, respectively.

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 receives $1,400,000 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. For the period ended March 31, 2010 and 2009, the related party general and administrative expenses reimbursed to the Partnership were $4,133,000 and $226,000, respectively.

Additionally, the Partnership s contract compression segment provides contract compression services to HPC. HPC also provides transportation service to the Partnership. At March 31, 2010 and for the three months then ended, 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 with HPC described above.

Additionally, for the three months ended March 31, 2010, the Partnership sold $195,000 in compression assets to HPC.

9. Segment Information

In 2009, 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 four reportable segments: (a) gathering and processing, (b) transportation, (c) contract compression and (d) corporate and others. 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.

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Notes to Unaudited Condensed Consolidated Financial Statements (Continued)

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. RIG 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 on-going 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 revenues 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.

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Notes to Unaudited Condensed Consolidated Financial Statements (Continued)

Results for each 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 Revenues						
For the three months ended March 31, 2010	$ 276,842	$	$ 34,979	$ 5,931	$	$ 317,752
For the three months ended March 31, 2009	243,527	7,544	38,488	566		290,125
Intersegment Revenues						
For the three months ended March 31, 2010			5,332	39	(5,371)	
For the three months ended March 31, 2009	(2,010)	5,064	810	105	(3,969)	
Cost of Sales						
For the three months ended March 31, 2010	222,134		3,281	(767)	(39)	224,609
For the three months ended March 31, 2009	182,842	1,054	2,317	(153)	(3,159)	182,901
Segment Margin						
For the three months ended March 31, 2010	54,708		37,030	6,737	(5,332)	93,143
For the three months ended March 31, 2009	58,675	11,554	36,981	824	(810)	107,224
Operation and Maintenance						
For the three months ended March 31, 2010	23,761		13,778	201	(5,329)	32,411
For the three months ended March 31, 2009	22,306	2,286	12,540	313	(1,403)	36,042
Depreciation and Amortization						
For the three months ended March 31, 2010	17,289		9,207	979		27,475
For the three months ended March 31, 2009	16,721	2,448	8,027	693		27,889
Income from Unconsolidated Subsidiary						
For the three months ended March 31, 2010		7,913				7,913
For the three months ended March 31, 2009		336				336
Assets						
March 31, 2010	1,089,360	477,717	917,753	78,717		2,563,547
December 31, 2009	1,046,619	453,120	926,213	107,462		2,533,414
Investment in Unconsolidated Subsidiary						
March 31, 2010		477,717				477,717
December 31, 2009		453,120				453,120
Goodwill						
March 31, 2010	63,232		164,882			228,114
December 31, 2009	63,232		164,882			228,114
Expenditures for Long-Lived Assets						
For the three months ended March 31, 2010	24,000	20,210	11,991	2,474		58,675
For the three months ended March 31, 2009	23,804	22,367	34,032	52		80,255

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

	Three Months Ended March 31, 2010	2009
	(in thousands)	
Net (loss) income attributable to Regency Energy Partners LP	$ (612)	$ 148,389
Add (deduct):		
Operation and maintenance	32,411	36,042
General and administrative	15,403	14,852
Loss (gain) on asset sales, net	284	(133,932)
Depreciation and amortization	27,475	27,889

Income from unconsolidated subsidiary	(7,913)	(336)
Interest expense, net	22,345	14,227
Other income and deductions, net	3,267	(42)
Income tax expense	321	100
Net income attributable to the noncontrolling interest	162	35
Total segment margin	$ 93,143	$ 107,224

10. Equity-Based Compensation

Common Unit Option and Restricted (Non-Vested) Units. The Partnership s LTIP for the Partnership s employees, directors and consultants covers an aggregate of 2,865,584 common units. Restricted (non-vested) awards generally vest on the basis of one-fourth of the award each year. All outstanding options have vested and expire ten years after the grant date. LTIP compensation expense of $1,376,000 is recorded in general and administrative in the statement of operations for the three months ended March 31, 2010.

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Notes to Unaudited Condensed Consolidated Financial Statements (Continued)

The common unit options activity for the three months ended March 31, 2010 is as follows.

Common Unit Options	Units	Weighted Average Exercise Price	Weighted Average Contractual Term (Years)	Aggregate Intrinsic Value *(in thousands)
Outstanding at the beginning of period	306,651	$ 21.50		
Granted				$
Exercised				
Forfeited or expired				
Outstanding at end of period	306,651	21.50	6.1	380
Exercisable at the end of the period	306,651			380

* 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.

The Partnership will make distributions to non-vested restricted common units at the same rate and on the same dates as the common units. Restricted common units are subject to contractual restrictions against transfer which lapse over time; non-vested restricted units are subject to forfeitures on termination of employment. The Partnership expects to recognize $8,344,000 of compensation expense related to the grants of restricted common units under LTIP primarily over the next 1.66 years.

The restricted (non-vested) common unit activity for the three months ended March 31, 2010 is as follows.

Restricted (Non-Vested) Common Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	464,009	$ 28.36
Granted		
Vested	(45,500)	28.76
Forfeited or expired	(19,250)	32.35
Outstanding at the end of period	399,259	28.12

Phantom Units. The Partnership s phantom units are in substance two grants composed of (1) service condition grants with graded vesting over three years; and (2) market condition grants with cliff vesting based upon the Partnership s relative ranking in total unitholder return among 20 peer companies, as disclosed in Item 11 of the Partnership s Annual Report on Form 10-K for the year ended December 31, 2009. At the end of the measurement period (March 15, 2012) for the market condition grants, the phantom units will convert to common units in a ratio ranging from 0 to 150 percent. For both the service condition grants and the market condition grants, distributions will be accumulated and paid upon vesting.

During the three months ended March 31, 2010, the Partnership awarded 8,500 phantom units to senior management and certain key employees. The Partnership expects to recognize $1,677,000 of compensation expense related to non-vested phantom units over a period of 2.2 years. During the three months ended March 31, 2010, the Partnership recognized $263,000 of expense, which was reflected in general and administrative expense in the statement of operations.

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Notes to Unaudited Condensed Consolidated Financial Statements (Continued)

The following table presents phantom unit activity for the three months ended March 31, 2010.

Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	301,700	$ 8.63
Service condition grants	8,500	21.81
Market condition grants		
Vested service condition	(39,598)	13.13
Vested market condition		
Forfeited service condition	(1,067)	12.46
Forfeited market condition	(2,400)	4.49
Total outstanding at end of period	267,135	10.38

11. Fair Value Measures

The fair value measurement 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 accessible markets;

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 commodity swaps and embedded derivatives in the Series A Preferred Units. Derivatives related to 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 Series A 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, common unit price, dividend yield, and expected volatility, and are classified as Level 3 in the hierarchy. The change in fair value of the derivatives related to Series A Preferred Units is recorded in other income and deductions, net within the statement of operations.

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

	March 31, 2010		December 31, 2009	
	Assets	Liabilities	Assets	Liabilities
	(in thousands)			

Level 1	$	$	$	$
Level 2	23,507	6,181	25,194	16,565
Level 3		47,979		44,594
Total	$ 23,507	$ 54,160	$ 25,194	$ 61,159

The following table presents the changes in Level 3 derivatives measured on a recurring basis for the three months ended March 31, 2010.

	Derivatives related to Series A Preferred Units March 31, 2010 (in thousands)
Beginning Balance	$ 44,594
Net unrealized losses included in other income and deductions, net	3,385
Ending Balance	$ 47,979

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 which incur interest under a floating interest rate structure. Accordingly, the carrying value approximates fair value. The estimated fair value of the senior notes due 2013 and 2016, based on third party market value quotations as of March 31, 2010, were $367,331,000 and $265,000,000, respectively.

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Notes to Unaudited Condensed Consolidated Financial Statements (Continued)

12. Subsequent Events

On April 26, 2010, 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 a distribution with respect to incentive distribution rights of approximately $713,000, payable on May 14, 2010, to unitholders of record at the close of business on May 7, 2010.

On April 30, 2010, the Partnership purchased 76,989 units representing general partner interests in HPC for an aggregate purchase price of $92,087,000 from EFS Haynesville, an affiliate of GECC and the Partnership. This purchase was funded using the Partnership s revolving credit facility and it increased the Partnership s ownership percentage in HPC from 43 percent to approximately 49.99 percent. The Partnership and EFS Haynesville also entered into a Voting Agreement which grants the Partnership the right to vote the general partner interest in HPC previously retained by EFS Haynesville. Because this transaction occurred between two entities that are under common control, partners capital will be reduced by a deemed distribution of the excess purchase price over EFS Haynesville s carrying amount during the second quarter of 2010.

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 historical consolidated financial statements and notes included elsewhere in this document.

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

RECENT DEVELOPMENTS

On April 30, 2010, we purchased 76,989 units representing general partner interests in HPC for an aggregate purchase price of $92,087,000 from EFS Haynesville, an affiliate of GECC and us. This purchase was funded using our revolving credit facility and it increased our ownership percentage in HPC from 43 percent to approximately 49.99 percent. We and EFS Haynesville also entered into a Voting Agreement which grants us the right to vote the general partner interest in HPC previously retained by EFS Haynesville. Because this transaction occurred between two entities that are under common control, our partners capital will be reduced by a deemed distribution of the excess purchase price over EFS Haynesville s carrying amount during the second quarter of 2010.

OUR OPERATIONS. We divide our operations into four 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 which, through RIGS, delivers natural gas from northwest Louisiana to markets as well as downstream pipelines in northeast Louisiana through a 450 mile intrastate pipeline system;

- *Contract Compression*: We provide turn-key natural gas compression services whereby we guarantee our customers 98 percent mechanical availability of our compression units for land installations and 96 percent mechanical availability for over-water installations; and

- *Corporate and Others:* We own and operate an interstate pipeline that consists of 10 miles of pipeline that extends from Harrison County, Texas to Caddo Parish, Louisiana. This pipeline has a FERC certified capacity of 150 MMcf/d.

HOW WE EVALUATE OUR OPERATIONS. Our management uses a variety of financial and operational measurements to analyze our performance. We view these measures as important tools for evaluating the success of our operations and review these measurements on a monthly basis for consistency and trend analysis. These measures include volumes, segment margin, total segment margin, adjusted segment margin, adjusted total segment margin, operating and maintenance expenses, EBITDA, and adjusted EBITDA on a segment and company-wide basis.

Volumes. We must continually obtain new supplies of natural gas to maintain or increase throughput volumes on our gathering and processing systems. Our ability to maintain existing supplies of natural gas and obtain new supplies is affected by (i) the level of workovers or recompletions of existing connected wells and successful drilling activity in areas currently dedicated to our gathering and processing systems, (ii) our ability to compete for volumes from successful new wells in other areas and (iii) our ability to obtain natural gas that has been released from other commitments. We routinely monitor producer activity in the areas served by our gathering and processing systems to pursue new supply opportunities.

Segment Margin and Total Segment Margin. We define segment margin, generally, as revenues minus cost of sales. We calculate our Gathering and Processing segment margin and Corporate and Others segment margin as our revenues generated from operations minus the cost of natural gas and NGLs purchased and other cost of sales, including third-party transportation and processing fees.

Prior to our contribution of RIGS to HPC, we calculated our Transportation segment margin as revenues generated by fee income as well as, in those instances in which we purchased and sold gas for our account, gas sales revenues minus the cost of natural gas that we purchased and transported. After our contribution of RIGS to HPC, we do not record segment margin for the Transportation segment because we record our ownership percentage of the net income in HPC as income from an unconsolidated subsidiary.

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.

We calculate total segment margin as the total of segment margin of our four segments, less the intersegment elimination.

Adjusted Segment Margin and Adjusted Total Segment Margin. We define adjusted segment margin as segment margin adjusted for non-cash gains (losses) from commodity derivatives. We define adjusted total segment margin as total segment margin adjusted for non-cash gains (losses) from commodity derivatives. Our adjusted total segment margin equals the sum of our operating segments adjusted segment margins or segment margins, including intersegment eliminations. Adjusted segment margin and adjusted total segment margin are included as supplemental disclosures because they are primary performance measures used by management as they represent the results of product purchases and sales, a key component of our operations.

Revenue Generating Horsepower. Revenue generating horsepower 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.

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

EBITDA and Adjusted EBITDA. We define EBITDA as net income (loss) plus interest expense, provision for income taxes and depreciation and amortization expense. We define adjusted EBITDA as EBITDA plus or minus the following:

- non-cash loss (gain) from commodity and embedded derivatives,
- loss (gain) on asset sales, net,
- loss on debt refinancing,
- other (income) expense, net, and
- the Partnership s interest in adjusted EBITDA from unconsolidated subsidiaries less income from unconsolidated subsidiary.

These measures are used as supplemental measures by our management and by external users of our financial statements such as investors, 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 Partner;
- 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.

Neither EBITDA nor adjusted EBITDA should be considered as an alternative to, or more meaningful than, 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 partnership. The following table presents a reconciliation of EBITDA and adjusted EBITDA to net cash flows provided by operating activities and to net (loss) income.

	Three Months Ended March 31, 2010	2009
	(in thousands)	
Reconciliation of Adjusted EBITDA to net cash flows provided by operating activities and to net (loss) income		
Net cash flows provided by operating activities	$ 32,781	$ 36,331
Add (deduct):		
Depreciation and amortization, including debt issuance cost amortization	(29,389)	(28,932)
Write-off of debt issuance costs	(1,780)	
Income from unconsolidated subsidiary	7,913	336
Derivative valuation change	(7,182)	3,565
(Loss) gain on assets sales, net	(284)	133,932
Unit based compensation expenses	(1,639)	(1,189)
Changes in current assets and liabilities		
Trade accounts receivable, accrued revenues and related party receivables	2,017	(22,741)
Other current assets	(1,091)	(10,458)
Trade accounts payable, accrued cost of gas and liquids, and related party payables	13,826	36,948
Other current liabilities	(12,131)	1,022
Distribution received from unconsolidated subsidiary	(3,526)	
Other assets and liabilities	35	(390)
Net (loss) income	(450)	148,424
Add (deduct):		
Interest expense, net	22,345	14,227
Depreciation and amortization	27,475	27,889
Income tax expense	321	100
EBITDA	49,691	190,640
Add (deduct):		
Non-cash loss (gain) from commodity and embedded derivatives	7,191	(3,565)
Loss (gain) on assets sales, net	284	(133,932)
Income from unconsolidated subsidiary	(7,913)	(336)
Partnership s ownership interest in HPC s adjusted EBITDA	10,675	590
Other expense, net	90	729
Adjusted EBITDA	$ 60,018	$ 54,126

The following table presents a reconciliation of adjusted total segment margin to net (loss) income.

	Three Months Ended March 31, 2010	2009
	(in thousands)	
Reconciliation of Adjusted total segment margin to net (loss) income		
Net (loss) income	$ (450)	$ 148,424
Add (deduct):		
Operation and maintenance	32,411	36,042
General and administrative	15,403	14,852
Loss (gain) on assets sales, net	284	(133,932)
Depreciation and amortization	27,475	27,889
Income from unconsolidated subsidiary	(7,913)	(336)
Interest expense, net	22,345	14,227
Other income and deductions, net	3,267	(42)
Income tax expense	321	100
Total segment margin	93,143	107,224

Add (deduct):				
Non-cash loss (gain) from commodity derivatives		3,806		(3,565)
Adjusted total segment margin	$	96,949	$	103,659

Cash Distributions. On April 26, 2010, 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 a distribution with respect to incentive distribution rights of approximately $713,000, payable on May 14, 2010, to unitholders of record at the close of business on May 7, 2010.

In addition, the Partnership will make a distribution of $0.445 per outstanding Series A Preferred Units, payable on May 14, 2010, to outstanding unitholders at the close of business on May 7, 2010.

RESULTS OF OPERATIONS

Partnership

Three Months Ended March 31, 2010 vs. Three Months Ended March 31, 2009

	Three Months Ended March 31, 2010	2009	Change	Percent
	(in thousands except percentages and volume data)			
Total revenues	$ 317,752	$ 290,125	$ 27,627	10%
Cost of sales	224,609	182,901	41,708	23
Total segment margin (1)	93,143	107,224	(14,081)	13
Operation and maintenance	32,411	36,042	(3,631)	10
General and administrative	15,403	14,852	551	4
(Gain) loss on asset sales, net	284	(133,932)	134,216	100
Depreciation and amortization	27,475	27,889	(414)	1
Operating income	17,570	162,373	(144,803)	89
Income from unconsolidated subsidiary	7,913	336	7,577	2,255
Interest expense, net	(22,345)	(14,227)	(8,118)	57
Other income and deductions, net	(3,267)	42	(3,309)	7,879
(Loss) income before income taxes	(129)	148,524	(148,653)	100
Income tax expense	321	100	221	221
Net (loss) income	(450)	148,424	(148,874)	100
Net income attributable to the noncontrolling interest	(162)	(35)	(127)	363
Net (loss) income attributable to Regency Energy Partners LP	$ (612)	$ 148,389	$ (149,001)	100 %
Gathering and processing segment margin	$ 54,708	$ 58,675	$ (3,967)	7%
Add (deduct):				
Non-cash gain (loss) from commodity derivatives	3,806	(3,565)	7,371	207
Adjusted gathering and processing segment margin	58,514	55,110	3,404	6
Transportation segment margin		11,554	(11,554)	100
Contract compression segment margin	37,030	36,981	49	
Corporate and others segment margin	6,737	824	5,913	718
Inter-segment eliminations	(5,332)	(810)	(4,522)	558
Adjusted total segment margin	$ 96,949	$ 103,659	$ (6,710)	6%
System inlet volumes (MMBtu/d) (2)	1,723,844	1,618,342	105,502	7%

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

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

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

	Three Months Ended March 31, 2010	2009	Change	Percent
	(in thousands except percentages and volume data)			
Gathering and Processing Segment				
Financial data:				
Adjusted segment margin (1)	$ 58,514	$ 55,110	$ 3,404	6 %
Operation and maintenance (2)	23,761	22,306	1,455	7
Operating data:				
Throughput (MMBtu/d) (3)	1,029,146	1,038,707	(9,561)	1
NGL gross production (Bbls/d)	25,742	22,721	3,021	13
Transportation Segment				
Financial data:				
Adjusted segment margin (1)	$	$ 11,554	$ (11,554)	100 %
Operation and maintenance (2)		2,286	(2,286)	100
Operating data:				
Throughput (MMBtu/d) (3)		812,332	(812,332)	100
Contract Compression				
Financial data:				
Segment margin (1)	$ 37,030	$ 36,981	$ 49	0%
Operation and maintenance (2)	13,778	12,540	1,238	10
Operating data:				
Revenue generating horsepower (4)	759,704	789,494	(29,790)	4%
Average horsepower per revenue generating compression unit	858	858		
Corporate and Others				
Financial data:				
Segment margin (1)	$ 6,737	$ 824	$ 5,913	718 %
Operation and maintenance (2)	201	313	(112)	36

(1) Combined adjusted segment margin for our segments differs from consolidated adjusted total segment margin due to intersegment eliminations.

(2) Combined operation and maintenance expense varies from consolidated operation and maintenance expense due to intersegment eliminations.

(3) Combined throughput volumes for the gathering and processing and transportation segments vary from consolidated system inlet volumes due to intersegment eliminations.

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

In addition to the revenue generating horsepower and compression units owned and operated by the Contract Compression segment disclosed below, the Contract Compression segment operates 139,961 horsepower owned by the gathering and processing segment as of March 31, 2010. The Contract Compression segment also operates 37,985 horsepower owned by HPC as of March 31, 2010.

Horsepower Range	March 31, 2010 Revenue Generating Horsepower	Percentage of Revenue Generating Horsepower	Number of Units
0-499	68,022	9%	360
500-999	70,912	9%	115
1,000+	620,770	82%	410
	759,704	100%	885

Horsepower Range	Revenue Generating Horsepower	December 31, 2009 Percentage of Revenue Generating Horsepower	Number of Units
0-499	65,397	9%	361
500-999	74,826	10%	121
1,000+	613,105	81%	405
	753,328	100%	887

Net (Loss) Income Attributable to Regency Energy Partners LP. Net loss attributable to Regency Energy Partners LP was $612,000 in the three months ended March 31, 2010, compared to the net income of $148,389,000 in the three months ended March 31, 2009. The major components of this change were as follows:

- $133,451,000 decrease due to the absence of gain associated with the contribution of RIGS to HPC;
- $14,081,000 decrease in segment margin primarily due to the contribution of RIGS to HPC;
- $8,118,000 increase in interest expense primarily due to the issuance of $250,000,000 of 9.375 percent senior notes due 2016 in May 2009 at a higher interest rate as compared to our credit facility interest rate;
- $3,309,000 decrease in other income and deductions, net which primarily relate to the non-cash value change associated with the embedded derivative related to the Series A Preferred Units issued in September 2009. These decreases were partially offset by:
- $7,577,000 increased income from an unconsolidated subsidiary (HPC) as there was a full quarter of operations in 2010 compared to only 14 days in 2009, plus the Haynesville Expansion Project and the Red River Lateral were in operation for two months in 2010; and
- $3,631,000 decrease in operations and maintenance expenses primarily as a result of the absence of HPC s operations and maintenance expenses in 2010, as well as a focus on cost saving measures.

Adjusted Total Segment Margin. Adjusted total segment margin decreased to $96,949,000 in the three months ended March 31, 2010 from $103,659,000 in the three months ended March 31, 2009. This was primarily attributable to a decrease of $11,554,000 in the transportation segment margin which was offset by the addition of $3,404,000 in adjusted gathering and processing segment margin and the addition of $5,913,000 in corporate and others segment.

Adjusted gathering and processing segment margin increased to $58,514,000 for the three months ended March 31, 2010 from $55,110,000 for the three months ended March 31, 2009, primarily due to the increased volumes in south Texas associated with the Eagle Ford Shale development.

We contributed RIGS to HPC on March 17, 2009. As a result, there was no transportation segment margin for the three months ended March 31, 2010.

Corporate and others segment margin increased to $6,737,000 in the three months ended March 31, 2010 from $824,000 in the three months ended March 31, 2009. The increase is primarily attributable to a $3,907,000 increase in management fees from HPC for general and administrative expenses.

Operation and Maintenance. Operation and maintenance expense decreased to $32,411,000 in the three months ended March 31, 2010 from $36,042,000 during the three months ended March 31, 2009. The decrease was primarily due to the following:

- $2,286,000 decrease due to the absence of HPC s operation and maintenance expenses in 2010; and
- $1,345,000 decrease due to a focus on cost saving measures.

Gain on Sale of Asset, net. Gain on sale of asset, net decreased due to the absence in 2010 of the gain associated with the contribution of RIGS to HPC on March 17, 2009.

Depreciation and Amortization. Depreciation and amortization expense decreased to $27,475,000 in the three months ended March 31, 2010 from $27,889,000 in the three months ended March 31, 2009. The decrease was primarily due to the contribution of RIGS to HPC which was $2,448,000, offset by $2,034,000 increase related to various organic growth projects completed since March 31, 2009.

Interest Expense, Net. Interest expense, net increased to $22,345,000 in the three months ended March 31, 2010 from $14,227,000 in the three months ended in March 31, 2009. The increase is primarily attributable to:

- $7,595,000 due to higher rates related to our senior notes interest rates as compared to our credit facility;

- $1,780,000 write-off of loan fees upon the execution of the fifth amendment of our revolving credit facility; and

- $475,000 less capitalized interest in the three months ended March 31, 2010 compared to the three months ended March 31, 2009; which was offset by;

- $1,732,000 due to a lower amount of borrowings.

Other Income and Deductions, net. Other income and deductions, net decreased to an expense of $3,267,000 in the three months ended March 31, 2010 from an income of $42,000 during the three months ended March 31, 2009. This increase is primarily attributable to the non-cash value change in the embedded derivatives related to the Series A Preferred Units issued in September 2009.

HPC

Although we own a 43 percent interest in HPC, the following management discussion and analysis is for 100 percent of HPC s consolidated results of operations. For comparative purposes only, we have combined the results of operations of RIG from January 1, 2009 to March 17, 2009, with the results of operations of HPC.

Three Months Ended March 31, 2010 vs. March 31, 2009

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

	Three Months Ended March 31, 2010	2009	Change	Percent
	(in thousands except percentages and volume data)			
Revenues	$ 35,189	$ 14,155	$ 21,034	149 %
Cost of sales	1,310	599	711	119
Segment margin	33,879	13,556	20,323	150
Operation and maintenance	4,774	2,611	2,163	83
General and administrative	4,318	248	4,070	1,641
Depreciation and amortization	6,321	3,117	3,204	103
Operating income	18,466	7,580	10,886	144
Interest expense	(102)		(102)	N/M
Other income and deductions, net	39	104	(65)	63
Net income	$ 18,403	$ 7,684	$ 10,719	139 %
System inlet volumes (MMbtu/d)	882,626	810,848	71,778	9%

N/M - not meaningful

The following provides a reconciliation of segment margin and adjusted segment margin to net income.

	Three Months Ended March 31, 2010	2009
	(in thousands)	
Net income	$ 18,403	$ 7,684
Add (deduct):		
Operation and maintenance	4,774	2,611
General and administrative	4,318	248
Depreciation and amortization	6,321	3,117
Interest expense	102	
Other income and deductions, net	(39)	(104)
Segment margin and adjusted segment margin	$ 33,879	$ 13,556

Net income increased to $18,403,000 in the three months ended March 31, 2010 from $7,684,000 in the three months ended March 31, 2009. The increase in net income was primarily attributable to the following:

$20,323,000 increase in segment margin since the Haynesville Expansion Project and the Red River Lateral were placed in service on January 27, 2010;

$4,070,000 increase in general and administrative expenses primarily due to the management fees paid to the Partnership;

$3,204,000 increase in depreciation and amortization expenses primarily due to the additional depreciation from the Haynesville Expansion Project and the Red River Lateral; and

$2,163,000 increase in operation and maintenance expenses primarily related to increased ad valorem taxes.

HPC s adjusted EBITDA for the three months ended March 31, 2010 and 2009 are presented below.

	Three Months Ended March 31, 2010	2009
	(in thousands)	
Net income	$ 18,403	$ 7,684
Add (deduct):		
Depreciation and amortization	6,321	3,117
Interest expense	102	
EBITDA and adjusted EBITDA	$ 24,826	$ 10,801

Cash Distributions. On January 7, 2010, the HPC management committee paid a distribution of $8,200,000, of which the Partnership received its pro-rata share of $3,526,000.

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, 2009.

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 6 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;
- borrowing under our credit facility;
- distributions received from unconsolidated subsidiaries;
- asset sales;
- debt offerings; and
- issuance of additional partnership units.

We expect our growth capital expenditures to be approximately $180,000,000 in 2010, exclusive of our 43 percent proportionate share of the growth capital expenditures related to HPC. Our anticipated 2010 organic growth capital expenditures include $148,000,000 for the expansion of our gathering and processing facilities, $24,000,000 for additional compression for our contract compression segment, and $8,000,000 related to the corporate and others segment.

In addition, we expect to invest $23,000,000 in HPC in 2010.

Although we intend to move forward with our 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 reduced by substantial cost of capital increases during this period.

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 obligations 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 derivative assets and liabilities due to fair value changes in our derivative positions being reflected on our balance sheet. These derivative assets and liabilities represent our expectations for the settlement of derivative rights and obligations over the next 12 months, and should 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 derivative assets and liabilities to affect our ability to pay expenditures and obligations as they come due. Our contract compression segment records deferred revenue as a current liability. The deferred revenue represents billings in advance of services performed. As the revenues associated with the deferred revenue are earned, the liability is reduced.

Our working capital decreased to $10,447,000 at March 31, 2010 from $17,468,000 at December 31, 2009. This decrease was primarily due to the following factors:

- an increase in other current liabilities of $12,131,000 due to the interest accrual on our senior notes, which pay interest semi-annually in June and December;

- a decrease in cash and cash equivalents of $5,741,000;

- a decrease in other current assets of $626,000; and was offset by

- a net increase in trade account receivable, accrued revenues, related party receivables, trade accounts payable, accrued cost of gas and liquids, deferred revenue and related party payables of $6,817,000 due to the timing of our cash receipts and payments; and

- a net increase in the market value of derivative assets and liabilities of $4,660,000 due to the decrease in commodity prices in the three months ended March 31, 2010.

Cash Flows from Operating Activities. Net cash flows provided by operating activities decreased to $32,781,000 in the three months ended March 31, 2010 from $36,331,000 in the three months ended March 31, 2009. The decrease is primarily due to the contribution of RIGS to HPC in March 2009.

Cash Flows from Investing Activities. Net cash flows used in investing activities increased to $48,043,000 in the three months ended March 31, 2010 from net cash flows provided by investing activities of $2,842,000 in the three months ended March 31, 2009. The increase is due to $20,210,000 increase in capital contribution associated with our investment in HPC, a $72,465,000 decrease in proceeds from asset sales and was offset by $41,790,000 decrease in capital expenditures.

Growth Capital Expenditures. Growth capital expenditures are capital expenditures 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 to maintain existing system volumes and related cash flows. In the three months ended March 31, 2010, we incurred $28,624,000 of growth capital expenditures, exclusive of growth capital expenditure for HPC. Growth capital expenditures for the three months ended March 31, 2010 relates to $20,941,000 for organic growth projects in our gathering and processing segment and $7,683,000 for the fabrication of new compressor packages for our contract compression segment.

Maintenance Capital Expenditures. Maintenance capital expenditures are capital expenditures made to replace partially or fully depreciated assets or to maintain the existing operating capacity of our assets and extend their useful lives. In the three months ended March 31, 2010, we incurred $3,942,000 of maintenance capital expenditures.

Cash Flows from Financing Activities. Net cash flows provided by financing activities increased to $9,521,000 in the three months ended March 31, 2010 from net cash flows used in financing activities of $33,194,000 in the three months ended March 31, 2009. The increase is due to an increase of $62,005,000 borrowing under our revolving credit facility, offset by a $9,264,000 increase in debt and equity issuance costs and a $10,026,000 increase in distributions.

Credit Ratings. Our credit ratings as of March 31, 2010 are provided below.

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

Fifth Amended and Restated Credit Agreement. On March 4, 2010, RGS executed the Fifth Amended and Restated Credit Agreement (the new credit agreement), to be effective on the same date. The material differences between the Fourth Amended and Restated Credit Agreement (the previous credit agreement) and the new credit agreement include:

- The extension of the maturity date to June 15, 2014 from August 15, 2011, subject to the following contingency:
  - If the Partnership s 8.375 percent senior notes due December 15, 2013 have not been refinanced or paid off by June 15, 2013, then the maturity date will be June 15, 2013;
- An increase in the amount of allowed investments in HPC to $250,000,000 from $135,000,000;
- The addition of an allowance for joint venture investments (other than HPC) of up to $75,000,000, provided that (i) distributed cash and net income from joint ventures under this basket shall be excluded from consolidated net income and (ii) equity interests in joint ventures created under this basket shall be pledged as collateral;
- The modification of financial covenants to give credit for projected EBITDA associated with certain future material HPC projects on a percentage of completion basis, provided that such amount, together with adjustments related to the Haynesville Expansion Project and other material projects, does not exceed 20 percent of consolidated EBITDA (as defined in the new credit agreement) through March 31, 2010, and 15 percent thereafter;
- An increase in the annual general asset sales permitted from $20,000,000 annually to five percent of consolidated net tangible assets (as defined in the new credit agreement) annually.

The credit agreement and the guarantees are senior to the Partnership s and the guarantors secured obligations, including the Series A Preferred Units, to the extent of the value of the assets securing such obligations. As of March 31, 2010, the Partnership was in compliance with all of the financial covenants contained within the revolving credit agreement.

Item 3. Quantitative and Qualitative Disclosure about Market Risk

Commodity Price Risk. We are a net seller of NGL, condensate and natural gas as a result of our gathering and processing operations. The prices of these commodities are impacted by changes in supply and demand as well as market uncertainty. Our profitability and cash flow are affected by the inherent volatility of these commodities, which could adversely affect our ability to make distributions to our unitholders. We manage this commodity price exposure through an integrated strategy that includes management of our contract portfolio, matching sales prices of commodities with purchases, optimization of our portfolio by monitoring basis and other price differentials in operating areas, and the use of derivative contracts. In some cases, we may not be able to match pricing terms or to cover our risk to price exposure with financial hedges, and we may be exposed to commodity price risk. It is our policy not to take any speculative positions with derivative contracts.

On April 5, 2010, we entered into additional NGLs swaps to hedge a portion of our 2011 NGLs sales.

We have executed swap contracts settled against condensate, ethane, propane, butane, natural gas, and natural gasoline market prices. We continually monitor our hedging and contract portfolio and expect to continue to adjust our hedge positions as conditions warrant. We have hedged expected equity exposure to declines in prices for NGLs, condensate and natural gas volumes produced for our account in the approximate percentages set for below:

	As of March 31, 2010		As of April 5, 2010	
	2010	**2011**	**2010**	**2011**
NGLs	73%	29%	73%	41%
Condensate	84%	50%	84%	50%
Natural gas	74%	23%	74%	23%

The following table sets forth certain information regarding our hedges for natural gas, NGLs, and WTI, outstanding at March 31, 2010. The relevant index price that we pay is the monthly average of the daily closing price for deliveries of commodities into Mont Belvieu, Texas, as reported by the Oil Price Information Service (OPIS). The relevant index price for natural gas is NYMEX on the pricing dates as defined by the swap contracts. The relevant index for WTI is the monthly average of the daily price of WTI as reported by the NYMEX.

Period	**Underlying**	**Notional Volume/Amount**	**We Pay**	**We Receive Weighted Average Price**		**Fair Value Asset/(Liablity) (in thousands)**
April 2010-September 2011	Ethane	668 (MBbls)	Index	$0.53 ($/gallon)	$	(115)
April 2010-September 2011	Propane	435 (MBbls)	Index	1.26 ($/gallon)		2,768
April 2010-December 2010	Iso Butane	70 (MBbls)	Index	1.76 ($/gallon)		720
April 2010-September 2011	Normal Butane	223 (MBbls)	Index	1.56 ($/gallon)		1,037
April 2010-September 2011	Natural Gasoline	163 (MBbls)	Index	2.09 ($/gallon)		2,087
April 2010-December 2011	West Texas Intermediate Crude	320 (MBbls)	Index	104.22 ($/Bbl)		5,926
April 2010-June 2011	Natural gas	3,105,000 (MMBtu)	Index	6.16 ($/MMBtu)		4,992
Credit risk adjustment						(89)
				Total Fair Value	$	17,326

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 March 31, 2010 to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is properly recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms.

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

PART II OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

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, 2009, 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.

Proposed TCEQ Rule. TCEQ has proposed a new Section 352 Oil and Gas Permit by Rule (PBR), which is applicable to gas pipeline facilities and provides an authorization for activities that produce more than a de minimis level of emissions, but too little emissions for other permitting options, if the conditions of PBR are met. If adopted, our compliance with the conditions in the proposed PBR may result in substantial increases in our capital expenditures and operating costs.

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

None.

Item 6. Exhibits

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

Exhibit 10.35	Fifth Amended and Restated Credit Agreement, dated March 4, 2010 (Incorporated by reference to Exhibit 10.1 to our Form 8-K dated March 4, 2010)
Exhibit 10.36	Amendment Agreement to the Fifth Amended and Restated Credit Agreement, dated March 4, 2010 (Incorporated by reference to Exhibit 10.2 to our Form 8-K dated March 4, 2010)
Exhibit 10.37	Assignment and Assumption Agreement, dated April 30, 2010, by and between EFS Haynesville, LLC and Regency Haynesville Intrastate Gas LLC (Incorporated by reference to Exhibit 10.1 to our Form 8-K dated April 30, 2010)
Exhibit 10.38	Voting Agreement, dated April 30, 2010, by and between EFS Haynesville, LLC and Regency Haynesville Intrastate Gas LLC (Incorporated by reference to Exhibit 10.2 to our Form 8-K dated April 30, 2010)
Exhibit 10.39	First Amendment To Second Amended and Restated General Partnership Agreement of RIGS Haynesville Partnership Co. dated as of March 9, 2010

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: May 7, 2010

/s/ LAWRENCE B. CONNORS
Lawrence B. Connors
Senior Vice President and Chief Accounting Officer

(Duly Authorized Officer)