Regency Energy Partners LP
Form 10-Q
May 05, 2011

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, 2011

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 **(State or other jurisdiction of** **incorporation or organization)**	**16-1731691** **(I.R.S. Employer** **Identification No.)**
2001 BRYAN STREET, SUITE 3700 **DALLAS, TX** **(Address of principal executive offices)**	**75201** **(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). x 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.

x Large accelerated filer	¨ 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 137,332,211 common units outstanding as of April 29, 2011.

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 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
Bbls/d	Barrels per day
Bcf/d	One billion cubic feet per day
BTU	A unit of energy needed to raise the temperature of one pound of water by one degree Fahrenheit
ERMH	ETP-Regency Midstream Holdings, LLC, a joint venture 70 percent owned by ETP and 30 perent owned by the Partnership. On May 4, 2011, the name of ERMH was changed to Lone Star NGL LLC.
ETE	Energy Transfer Equity, L.P.
ETE GP	ETE GP Acquirer LLC
ETP	Energy Transfer Partners, L.P.
FASB	Financial Accounting Standards Board
Finance Corp.	Regency Energy Finance Corp., a wholly-owned subsidiary of the Partnership
GAAP	Accounting principles generally accepted in the United States of America
GE	General Electric Company
GE EFS	General Electric Energy Financial Services, a unit of GECC, combined with Regency GP Acquirer LP and Regency 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
GPM	Gallons per minute
GP Seller	Regency GP Acquirer, L.P.
HPC	RIGS Haynesville Partnership Co., a general partnership, and its 100 percent owned subsidiary, Regency Intrastate Gas LP
IDRs	Incentive Distribution Rights
IRS	Internal Revenue Service
ISDA	International Swap Dealers Association
KMP	Kinder Morgan Energy Partners, L.P.
LDH	LDH Energy Asset Holdings LLC
LIBOR	London Interbank Offered Rate
LTIP	Long-Term Incentive Plan
MEP	Midcontinent Express Pipeline LLC
MLP	Master Limited Partnership
MMbtu	One million BTUs
MMbtu/d	One million BTUs per day
MMcf	One million cubic feet
MMcf/d	One million cubic feet per day
NGLs	Natural gas liquids, including ethane, propane, normal butane, iso butane and natural gasoline
NYMEX	New York Mercantile Exchange
Partnership	Regency Energy Partners LP
RGS	Regency Gas Services LP, a wholly-owned subsidiary of the Partnership
RIGS	Regency Intrastate Gas System
SEC	Securities and Exchange Commission
Series A Preferred Units	Series A convertible redeemable preferred units
Services Co.	ETE Services Company, LLC
Tcf	One trillion cubic feet
Tcf/d	One trillion cubic feet per day
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 pipelines and our gathering and processing facilities, and for our customers of contract compression and contract treating businesses;
- 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, including those that relate to climate change and environmental protection;
- 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, 2010 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.

PART I   FINANCIAL INFORMATION

Item 1.   Financial Statements

As disclosed in Note 1, on May 26, 2010, GP Seller sold all of the outstanding membership interests of the Partnership s General Partner to ETE, effecting a change in control of the Partnership. In connection with this transaction, the Partnership s assets and liabilities were adjusted to fair value at the acquisition date by application of push-down accounting. As a result, the Partnership s unaudited condensed consolidated financial statements and certain footnote disclosures are presented in two distinct periods to indicate the application of two different bases of accounting between the periods presented: (1) the period prior to the acquisition date (May 26, 2010), identified as Predecessor and (2) the period from May 26, 2010 forward, identified as Successor .

Regency Energy Partners LP

Condensed Consolidated Balance Sheets

(in thousands except unit data)

(unaudited)

	March 31, 2011	December 31, 2010
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 24,724	$ 9,400
Trade accounts receivable, net of allowance of $372 and $297	30,388	35,212
Accrued revenues	69,279	74,017
Related party receivables	35,490	32,342
Derivative assets	1,559	2,650
Other current assets	9,499	7,384
Total current assets	170,939	161,005
Property, Plant and Equipment:		
Gathering and transmission systems	551,318	543,286
Compression equipment	828,131	812,428
Gas plants and buildings	210,078	185,741
Other property, plant and equipment	104,419	81,295
Construction-in-progress	90,859	97,439
Total property, plant and equipment	1,784,805	1,720,189
Less accumulated depreciation	(92,171)	(59,971)
Property, plant and equipment, net	1,692,634	1,660,218
Other Assets:		
Investment in unconsolidated subsidiaries	1,332,899	1,351,256
Long-term derivative assets		23
Other, net of accumulated amortization of debt issuance costs of $4,921 and $3,326	35,523	37,758
Total other assets	1,368,422	1,389,037
Intangible Assets and Goodwill:		
Intangible assets, net of accumulated amortization of $22,902 and $15,584	762,837	770,155
Goodwill	789,789	789,789
Total intangible assets and goodwill	1,552,626	1,559,944
TOTAL ASSETS	$ 4,784,621	$ 4,770,204
LIABILITIES & PARTNERS CAPITAL AND NONCONTROLLING INTEREST		
Current Liabilities:		
Trade accounts payable	$ 37,841	$ 50,208
Accrued cost of gas and liquids	75,837	80,756
Related party payables	12,051	3,338
Deferred revenues, including related party amounts of $2,599 and $8,765	18,653	25,257
Derivative liabilities	23,190	13,172
Other current liabilities	34,031	23,419
Total current liabilities	201,603	196,150
Long-term derivative liabilities	58,875	61,127

Other long-term liabilities	6,426	6,521
Long-term debt, net	1,215,839	1,141,061
Commitments and contingencies		
Series A convertible redeemable preferred units, redemption amount of $83,891 and $83,891	70,991	70,943
Partners Capital and Noncontrolling Interest:		
Common units (138,976,777 and 138,255,919 units authorized; 137,328,994 and 137,281,336 units issued and outstanding at March 31, 2011 and December 31, 2010)	2,891,594	2,940,732
General partner interest	332,036	333,077
Accumulated other comprehensive loss	(24,666)	(11,099)
Total partners capital	3,198,964	3,262,710
Noncontrolling interest	31,923	31,692
Total partners capital and noncontrolling interest	3,230,887	3,294,402
TOTAL LIABILITIES AND PARTNERS CAPITAL AND NONCONTROLLING INTEREST	$ 4,784,621	$ 4,770,204

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)

	Successor Three Months Ended March 31, 2011	Predecessor Three Months Ended March 31, 2010
REVENUES		
Gas sales, including related party amounts of $1,262 and $0	$ 110,087	$ 140,904
NGL sales, including related party amounts of $72,993 and $0	118,251	89,806
Gathering, transportation and other fees, including related party amounts of $6,216 and $8,520	81,836	69,485
Net realized and unrealized loss from derivatives	(1,714)	(939)
Other, including related party amounts of $1,866 and $0	8,792	5,529
Total revenues	317,252	304,785
OPERATING COSTS AND EXPENSES		
Cost of sales, including related party amounts of $3,214 and $3,366	216,261	217,271
Operation and maintenance	33,672	28,527
General and administrative, including related party amounts of $3,905 and $0	18,997	15,403
Loss on asset sales, net	28	284
Depreciation and amortization	40,236	24,895
Total operating costs and expenses	309,194	286,380
OPERATING INCOME	8,058	18,405
Income from unconsolidated subsidiaries	23,808	7,913
Interest expense, net	(20,007)	(20,482)
Loss on debt refinancing, net		(1,780)
Other income and deductions, net	2,414	(3,273)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	14,273	783
Income tax (benefit) expense	(32)	321
INCOME FROM CONTINUING OPERATIONS	$ 14,305	$ 462
DISCONTINUED OPERATIONS		
Net loss from operations of east Texas assets		(912)
NET INCOME (LOSS)	$ 14,305	$ (450)
Net income attributable to noncontrolling interest	(231)	(162)
NET INCOME (LOSS) ATTRIBUTABLE TO REGENCY ENERGY PARTNERS LP	$ 14,074	$ (612)
Amounts attributable to Series A convertible redeemable preferred units	1,993	2,001
General partner s interest, including IDRs	1,292	662
Amount allocated to non-vested common units		(79)
Limited partners interest in net income (loss)	$ 10,789	$ (3,196)

Basic and diluted income (loss) from continuing operations per common unit:

Amount allocated to common units	$	10,789	$	(2,306)
Weighted average number of common units outstanding		137,304,783		92,761,787
Basic income (loss) from continuing operations per common unit	$	0.08	$	(0.02)
Diluted income (loss) from continuing operations per common unit	$	0.07	$	(0.02)
Distributions paid per unit	$	0.445	$	0.445
Basic and diluted income (loss) on discontinued operations per common unit:	$		$	(0.01)
Basic and diluted net income (loss) per common unit:				
Amount allocated to common units	$	10,789	$	(3,196)
Basic net income (loss) per common unit	$	0.08	$	(0.03)
Diluted net income (loss) per common unit	$	0.07	$	(0.03)

See accompanying notes to condensed consolidated financial statements

Regency Energy Partners LP

Condensed Consolidated Statements of Comprehensive Income

Unaudited

(in thousands)

	Successor Three Months Ended March 31, 2011	Predecessor Three Months Ended March 31, 2010
Net income (loss)	$ 14,305	$ (450)
Net hedging amounts reclassified to earnings	3,429	2,657
Change in fair value of cash flow hedges	(16,996)	9,837
Comprehensive income	$ 738	$ 12,044
Comprehensive income attributable to noncontrolling interest	231	162
Comprehensive income attributable to Regency Energy Partners LP	$ 507	$ 11,882

See accompanying notes to condensed consolidated financial statements

Regency Energy Partners LP

Condensed Consolidated Statements of Cash Flows

Unaudited

(in thousands)

	Successor Three Months Ended March 31, 2011	Predecessor Three Months Ended March 31, 2010
OPERATING ACTIVITIES		
Net income (loss)	$ 14,305	$ (450)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:		
Depreciation and amortization, including debt issuance cost amortization and bond premium amortization	41,649	29,389
Write-off of debt issuance costs and bond premium		1,780
Amortization of excess fair value of unconsolidated subsidiaries	1,462	
Income from unconsolidated subsidiaries	(25,270)	(7,913)
Derivative valuation changes	(4,686)	7,182
Loss on asset sales, net	28	284
Unit-based compensation expenses	921	1,639
Cash flow changes in current assets and liabilities:		
Trade accounts receivable, accrued revenues and related party receivables	7,300	(2,017)
Other current assets	(2,096)	1,091
Trade accounts payable, accrued cost of gas and liquids, related party payables and deferred revenues	(12,145)	(13,826)
Other current liabilities	10,613	12,131
Distributions received from unconsolidated subsidiaries	25,270	3,526
Cash flow changes in other assets and liabilities	15	(35)
Net cash flows provided by operating activities	57,366	32,781
INVESTING ACTIVITIES		
Capital expenditures	(68,633)	(38,465)
Capital contributions to unconsolidated subsidiaries		(20,210)
Distributions in excess of earnings of unconsolidated subsidiaries	16,895	
Proceeds from asset sales	6	10,632
Net cash flows used in investing activities	(51,732)	(48,043)
FINANCING ACTIVITIES		
Net borrowings under revolving credit facility	75,000	69,009
Debt issuance costs	(184)	(15,272)
Partner distributions	(63,599)	(43,034)
Disposition of assets between entities under common control in excess of historical cost	25	
Distributions to noncontrolling interest		(1,135)
Proceeds from issuance of common units under LTIP, net of tax withholding	393	
Proceeds from equity issuances, net of issuance costs		(47)
Distributions to Series A convertible redeemable preferred units	(1,945)	
Net cash flows provided by financing activities	9,690	9,521
Net change in cash and cash equivalents	15,324	(5,741)

Cash and cash equivalents at beginning of period		9,400		9,827
Cash and cash equivalents at end of period	$	24,724	$	4,086
Supplemental cash flow information:				
Accrued capital expenditures	$	16,605	$	9,936

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 Loss**	**Noncontrolling Interest**	**Total**
Balance - December 31, 2010	137,281,336	$ 2,940,732	$ 333,077	$ (11,099)	$ 31,692	$ 3,294,402
Issuance of common units under LTIP, net of forfeitures and tax withholding	47,658	393				393
Unit-based compensation expenses		921				921
Disposition of assets between entities under common control in excess of historical cost			25			25
Partner distributions		(61,236)	(2,319)			(63,555)
Accrued distributions to phantom units		(44)				(44)
Net income		12,782	1,292		231	14,305
Distributions to Series A convertible redeemable preferred units		(1,906)	(39)			(1,945)
Accretion of Series A convertible redeemable preferred units		(48)				(48)
Net cash flow hedge amounts reclassified to earnings				3,429		3,429
Change in fair value of cash flow hedges				(16,996)		(16,996)
Balance - March 31, 2011	137,328,994	$ 2,891,594	$ 332,036	$ (24,666)	$ 31,923	$ 3,230,887

See accompanying notes to condensed consolidated financial statements

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Regency Energy Partners LP

Notes to Unaudited Condensed Consolidated Financial Statements

1. Organization and Summary of Significant Accounting Policies

Organization. The unaudited condensed consolidated financial statements presented herein contain the results of Regency Energy Partners LP (the Partnership) and its subsidiaries. The Partnership and its subsidiaries are engaged in the business of gathering, processing and transporting natural gas and NGLs as well as providing contract compression and contract treating services. Regency GP LP is the Partnership s general partner and Regency GP LLC (collectively the General Partner) is the managing general partner of the Partnership and the general partner of Regency GP LP.

Basis of Presentation. In May 2010, GP Seller completed the sale of all of the outstanding membership interests of the General Partner pursuant to a Purchase Agreement (the Purchase Agreement) among itself, ETE and ETE GP (the ETE Acquisition). Prior to the closing of the Purchase Agreement, GP Seller, an affiliate of GE EFS, owned all of the outstanding limited partner interests in the General Partner and, as a result of that position, controlled the Partnership. As a result of this transaction, the outstanding voting interests of the General Partner and control of the Partnership were transferred from GE EFS to ETE.

In connection with this change in control, the Partnership s assets and liabilities were adjusted to fair value on the closing date (May 26, 2010) by application of push-down accounting (the Push-down Adjustments). Due to the Push-down Adjustments, the Partnership s unaudited condensed consolidated financial statements and certain footnote disclosures are presented in two distinct periods to indicate the application of two different bases of accounting between the periods presented: (1) the period prior to the acquisition date (May 26, 2010), identified as Predecessor and (2) the period from May 26, 2010 forward, identified as Successor .

The unaudited financial information included in this Form 10-Q 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, 2010. 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. Certain prior year numbers have been conformed to the current year presentation.

Use of Estimates. The unaudited condensed consolidated financial statements have been prepared in conformity with GAAP, which includes the use of estimates and assumptions by management that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities that exist at the date of the condensed consolidated financial statements. Although these estimates are based on management s available knowledge of current and expected future events, actual results could be different from those estimates.

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

	Customer Relations	Trade Names	Total
		(in thousands)	
Balance at December 31, 2010	$ 706,566	$ 63,589	$ 770,155
Amortization	(6,500)	(818)	(7,318)
Balance at March 31, 2011	$ 700,066	$ 62,771	$ 762,837

As of March 31, 2011, the amortization periods of customer relations and trade names vary between 20 and 30 years. The expected amortization of the intangible assets for each of the five succeeding years is as follows.

Regency Energy Partners LP

Notes to Unaudited Condensed Consolidated Financial Statements (Continued)

Year ending December 31,	Total (in thousands)
2011 (remaining)	$ 21,883
2012	29,177
2013	29,177
2014	29,177
2015	29,177

2. Income per Limited Partner Unit

The following table provides a reconciliation of the numerator and denominator of the basic and diluted earnings per unit computations for the three months ended March 31, 2011. For the three months ended March 31, 2010, diluted earnings per unit equaled basic earnings per unit because all instruments were antidilutive.

	Three Months Ended March 31, 2011		
	Income (Numerator)	Units (Denominator)	Per-Unit Amount
	(in thousands except unit and per unit data)		
Basic income from continuing operations per unit			
Limited Partners interest	$ 10,789	137,304,783	$ 0.08
Effect of Dilutive Securities			
Common unit options		31,056	
Phantom units *		222,124	
Series A Preferred Units	(582)	4,584,192	
Diluted income from continuing operations per unit	$ 10,207	142,142,155	$ 0.07

* Amount assumes maximum conversion rate for market condition awards.

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

	Successor Three Months Ended March 31, 2011	Predecessor Three Months Ended March 31, 2010
Restricted (non-vested) common units		421,072
Phantom units *		386,706
Common unit options		306,651
Series A Preferred Units		4,371,586

* Amount assumes maximum conversion rate for market condition awards.

3. Investment in Unconsolidated Subsidiaries

HPC. The Partnership owns a 49.99 percent general partner interest in HPC. The following table summarizes the changes in the Partnership s ownership interest in HPC. As of March 31, 2011 and December 31, 2010, the carrying value of the Partnership s interest in HPC was

$695,659,000 and $698,774,000, respectively.

	Successor Three Months Ended March 31, 2011 (in thousands)	Predecessor Three Months Ended March 31, 2010 (in thousands)
Contributions to HPC	$	$ 20,210
Distributions received from HPC	16,728	3,526
Partnership s share of HPC s net income	15,075	7,913
Amortization of excess fair value of investment in HPC	(1,462)	

Regency Energy Partners LP

Notes to Unaudited Condensed Consolidated Financial Statements (Continued)

The summarized financial information of HPC at 100 percent level is disclosed below.

RIGS Haynesville Partnership Co.

Condensed Consolidated Balance Sheets

Unaudited

(in thousands)

	March 31, 2011	December 31, 2010
ASSETS		
Total current assets	$ 40,492	$ 30,074
Property, plant and equipment, net	895,580	888,892
Total other assets	148,033	148,162
TOTAL ASSETS	$ 1,084,105	$ 1,067,128
LIABILITIES & PARTNERS CAPITAL		
Total current liabilities	$ 18,798	$ 14,810
Long-term debt	52,000	33,000
Partners capital	1,013,307	1,019,318
TOTAL LIABILITIES & PARTNERS CAPITAL	$ 1,084,105	$ 1,067,128

RIGS Haynesville Partnership Co.

Condensed Consolidated Income Statements

Unaudited

(in thousands)

	For The Three Months Ended	
	March 31, 2011	March 31, 2010
Total revenues	$ 48,649	$ 35,189
Total operating costs and expenses	18,322	16,723
OPERATING INCOME	30,327	18,466
Interest expense, net	(136)	(102)
Other income and deductions, net	(35)	39
NET INCOME	$ 30,156	$ 18,403

MEP. The Partnership acquired a 49.9 percent interest in MEP in May 2010. As of March 31, 2011 and December 31, 2010, the carrying value of the Partnership s interest in MEP was $637,240,000 and $652,482,000, respectively. During the three months ended March 31, 2011, the

Partnership recognized $10,195,000 in income from unconsolidated subsidiaries for its ownership interest in MEP and received $25,437,000 in distributions from MEP.

The summarized financial information of MEP at 100 percent level is disclosed below.

Midcontinent Express Pipeline LLC

Condensed Balance Sheet

Unaudited

(in thousands)

	March 31, 2011	December 31, 2010
ASSETS		
Total current assets	$ 29,627	$ 39,746
Property, plant and equipment, net	2,204,060	2,221,193
Total other assets	5,279	5,224
TOTAL ASSETS	$ 2,238,966	$ 2,266,163
LIABILITIES & PARTNERS CAPITAL		
Total current liabilities	$ 57,547	$ 54,265
Long-term debt	799,064	799,018
Partners capital	1,382,355	1,412,880
TOTAL LIABILITIES & PARTNERS CAPITAL	$ 2,238,966	$ 2,266,163

Regency Energy Partners LP

Notes to Unaudited Condensed Consolidated Financial Statements (Continued)

Midcontinent Express Pipeline LLC

Condensed Income Statement

Unaudited

(in thousands)

	For The Three Months Ended March 31, 2011
Total revenues	$ 64,824
Total operating costs and expenses	31,559
OPERATING INCOME	33,265
Interest expense, net	(12,855)
NET INCOME	$ 20,410

4. Derivative Instruments

Policies. The Partnership established comprehensive risk management policies and procedures to monitor and manage the market risks associated with commodity prices, counterparty credit and interest rates. The General Partner is responsible for delegation of transaction authority levels, and the Audit and Risk Management Committee of the General Partner is responsible for the oversight of these risks, including monitoring exposure limits. The Audit and 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 operations. The prices of these commodities are impacted by changes in the supply and demand as well as other market forces. 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 cover its risk to price exposure with financial hedges, and it may be exposed to commodity price risk. Speculative positions with derivative contracts are prohibited under the Partnership s policies.

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

	As of March 31, 2011	
	2011	2012
NGLs	80%	42%
Condensate	86%	55%
Natural gas	60%	18%

At March 31, 2011, all of the Partnership s commodity swaps were 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 revolving credit facility. As of March 31, 2011, the Partnership had $360,000,000 of outstanding borrowings exposed to variable interest rate risk. In April 2010, the

Partnership entered into two-year interest rate swaps related to $250,000,000 of borrowings under its revolving credit facility, effectively locking the base rate, exclusive of applicable margins, for these borrowings at 1.325 percent through April 2012. The Partnership accounts for these interest rate swaps using the mark-to-market method of accounting.

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

The Partnership is exposed to credit risk from its derivative counterparties. The Partnership does not require collateral from these counterparties. The Partnership deals primarily with financial institutions when entering into financial derivatives. The Partnership has entered into Master ISDA Agreements that allow for netting of swap contract receivables and payables in the event of default by either party. If the Partnership s counterparties fail to perform under existing swap contracts, the Partnership s maximum loss as of March 31, 2011 would be $1,559,000, which would be reduced in full 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.

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Notes to Unaudited Condensed Consolidated Financial Statements (Continued)

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.

Quantitative Disclosures. The Partnership expects to reclassify $19,537,000 of net hedging losses to revenues from accumulated other comprehensive loss in the next 12 months.

The Partnership s derivative assets and liabilities, including credit risk adjustment, as of March 31, 2011 and December 31, 2010 are detailed below.

	Assets		Liabilities	
	March 31, 2011	December 31, 2010	March 31, 2011	December 31, 2010
	(in thousands)			
Derivatives designated as cash flow hedges				
Current amounts				
Commodity contracts	$ 1,559	$ 2,650	$ 20,996	$ 11,421
Long-term amounts				
Commodity contracts		23	4,427	3,271
Total cash flow hedging instruments	1,559	2,673	25,423	14,692
Derivatives not designated as cash flow hedges				
Current amounts				
Interest rate contracts			2,194	1,751
Long-term amounts				
Interest rate contracts				833
Embedded derivatives in Series A Preferred Units			54,448	57,023
Total derivatives not designated as cash flow hedges			56,642	59,607
Total derivatives	$ 1,559	$ 2,673	$ 82,065	$ 74,299

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Notes to Unaudited Condensed Consolidated Financial Statements (Continued)

The Partnership s statement of operations for the three months ended March 31, 2011 and 2010 were impacted by derivative instruments activities as follows.

		Successor Three Months Ended March 31, 2011	Predecessor Three Months Ended March 31, 2010
		(in thousands)	
		Change in Value Recognized in OCI on Derivatives (Effective Portion)	
Derivatives in cash flow hedging relationships:			
Commodity derivatives		$ (16,996)	$ 6,943
		$ (16,996)	$ 6,943
	Location of Gain/(Loss) Recognized in Income	**Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)**	
Derivatives in cash flow hedging relationships:			
Commodity derivatives	Revenues	$ (3,429)	$ (4,491)
Interest rate swap derivatives	Interest expense		(1,060)
		$ (3,429)	$ (5,551)
	Location of Gain/(Loss) Recognized in Income	**Amount of Gain/(Loss) Recognized in Income on Ineffective Portion**	
Derivatives in cash flow hedging relationships:			
Commodity derivatives	Revenues	$ 88	$ (498)
		$ 88	$ (498)
	Location of Gain/(Loss) Recognized in Income	**Amount of Gain/(Loss) Recognized in Income on Pre-Hedge Designation Fair Value**	
Derivatives in cash flow hedging relationships:			
Commodity derivatives	Revenues	$ 1,627	$
		$ 1,627	$
	Location of Gain/(Loss) Recognized in Income	**Amount of Gain/(Loss) from Dedesignation Amortized from AOCI into Income**	
Derivatives not designated in a hedging relationship:			
Commodity derivatives	Revenues	$	$ 2,894
Interest rate swap derivatives	Interest expense		

		$	$ 2,894

	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) Recognized in Income on Derivatives	
Derivatives not designated in a hedging relationship:			
Commodity derivatives	Revenues	$	$ 1,156
Interest rate swap derivatives	Interest expense	(259)	
Embedded derivatives	Other income & deductions	2,575	(3,385)
		$ 2,316	$ (2,229)

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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 revolving credit facility are as follows.

	March 31, 2011	December 31, 2010
	(in thousands)	
Senior notes	$ 855,839	$ 856,061
Revolving loans	360,000	285,000
Total	1,215,839	1,141,061
Less: current portion		
Long-term debt	$ 1,215,839	$ 1,141,061
Availability under revolving credit facility:		
Total credit facility limit	$ 900,000	$ 900,000
Revolving loans	(360,000)	(285,000)
Letters of credit	(15,515)	(16,015)
Total available	$ 524,485	$ 598,985

Long-term debt maturities as of March 31, 2011 for each of the next five years are as follows.

Year Ended December 31,	Amount (in thousands)
2011	$
2012	
2013	
2014	360,000
2015	
Thereafter	850,000*
Total	$ 1,210,000

* Excludes an unamortized premium of $5,839,000 as of March 31, 2011.

Revolving Credit Facility. The Partnership s $900,000,000 revolving credit facility expires on June 15, 2014. The revolving credit facility and guarantees are senior to the Partnership s and the guarantor s unsecured obligations, to the extent of the value of the assets securing such obligations. The revolving credit facility contains financial covenants requiring RGS and its subsidiaries to maintain debt to consolidated EBITDA (as defined in the credit agreement) ratio less than 5.25. At March 31, 2011, RGS and its subsidiaries were in compliance with these covenants.

The outstanding balance under the revolving 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 average interest rates, including commitment fees, were 3.1 percent and 3.93 percent, respectively, during the three months ended March 31, 2011 and 2010.

Senior Notes. The Partnership s $250,000,000 senior notes bear an annual interest rate of 9.375 percent and will mature on June 1, 2016. The Partnership s $600,000,000 senior notes bear an annual interest rate of 6.875 percent and will mature on December 1, 2018. These senior notes are jointly and severally guaranteed by all of the Partnership s current consolidated subsidiaries, other than Finance Corp. and a minor subsidiary, 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 unsecured 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 revolving credit facility, to the extent of the value of the assets securing such obligations. As of March 31, 2011, the Partnership was in compliance with 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 for a minor subsidiary, the Partnership has not included condensed consolidated financial information of guarantors of the senior notes.

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Notes to Unaudited Condensed Consolidated Financial Statements (Continued)

6. Commitments and Contingencies

Legal. The Partnership is involved in various claims, lawsuits and audits by taxing authorities 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.

Keyes Litigation. In August 2008, Keyes Helium Company, LLC (Keyes) filed suit against RGS, 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. On May 7, 2010, the jury rendered a verdict in favor of the Partnership. No damages were awarded to the Plaintiffs. Plaintiffs have appealed the verdict. The hearing on appeal will likely take place in late 2011 or early 2012.

MEP Guarantee. Upon its acquisition of the 49.9 percent interest in MEP from ETE, the Partnership agreed to indemnify ETP for any costs related to ETP s guarantee of payments under MEP s senior revolving credit facility (the MEP Facility). ETP continued to guarantee 50 percent of the obligations of the MEP Facility, with the remaining 50 percent of MEP Facility obligations guaranteed by KMP. The MEP Facility matured on February 28, 2011.

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, 2011, the Series A Preferred Units were convertible to 4,614,250 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 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, 2011.

	For the Three Months Ended March 31, 2011	
	Units	**Amount (in thousands)**
Balance at January 1, 2011	4,371,586	$ 70,943
Accretion to redemption value		48
Ending balance as of March 31, 2011	4,371,586	$ 70,991*

* This amount will be accreted to $80,000,000 plus any accrued and unpaid distributions by deducting amounts from partners capital over the 18.5 remaining years.

8. Related Party Transactions

Transactions with ETE. Under a services agreement with Services Co., Services Co. performs certain services for the Partnership. The Partnership pays Services Co s direct expenses for these services, plus an annual fee of $10,000,000, and receives the benefit of any cost savings recognized for these services. The services agreement has a five year term from May 26, 2010 to May 26, 2015, subject to earlier termination rights in the event of a change in control, the failure to achieve certain cost savings for the Partnership or upon an event of default. The Partnership incurred service fees of $3,905,000 for the three months ended March 31, 2011.

In conjunction with distributions by the Partnership to the limited and general partner interests, ETE received cash distributions of $14,008,000 during the three months ended March 31, 2011.

The Partnership s Contract Compression segment provides contract compression services to subsidiaries of ETP and records revenues in gathering, transportation and other fees on the statement of operations.

The Partnership s Contract Compression segment sold compression equipment to a subsidiary of ETP for $765,000 during the three months ended March 31, 2011. As this is a transaction between entities under common control, partners capital was increased by $25,000, which represented a deemed contribution of the excess sales price over the carrying value of $740,000.

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Notes to Unaudited Condensed Consolidated Financial Statements (Continued)

Transactions with HPC. Under a master services agreement with HPC, the Partnership operates and provides all employees and services for the operation and management of HPC. During the three months ended March 31, 2011 and March 31, 2010, the related party general and administrative expenses reimbursed to the Partnership were $4,200,000 and $4,133,333, respectively, which is recorded in gathering, transportation and other fees on the statement of operations.

The Partnership s Contract Compression segment provides contract compression services to HPC and records revenues in gathering, transportation and other fees on the statement of operations. The Partnership also receives transportation services from HPC and records it as cost of sales.

Transactions with Enterprise. Enterprise Products Partners L.P. (EPD) owns approximately 18 percent of ETE s outstanding common units; therefore, it is considered a related party along with any of its subsidiaries. The Partnership, in the ordinary course of business, sells natural gas and NGLs to subsidiaries of EPD and records the revenues in gas sales and NGL sales. The Partnership also incurs NGL processing fees and transportation fees with subsidiaries of EPD and records these fees as cost of sales.

Others. Prior to December 31, 2010, the employees operating the assets of the Partnership and its subsidiaries and all those providing staff or support services were 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. Effective January 1, 2011, certain employees of the Partnership became employees of ETP, and the Partnership reimburses ETP for all direct and indirect expenses incurred on behalf of the Partnership related to those employees. For the three months ended March 31, 2011, reimbursements of $20,351,000 and $5,510,000 to the General Partner and ETP, respectively, were recorded in the Partnership s financial statements as operating expenses or general and administrative expenses, as appropriate. For the three months ended March 31, 2010, reimbursement of $20,732,000 to the General Partner were recorded in the Partnership s financial statements as operating expenses or general and administrative expenses, as appropriate.

As of March 31, 2011 and December 31, 2010, details of the Partnership s related party receivables and related party payables were as follows.

	March 31, 2011	December 31, 2010
	(in thousands)	
Related party receivables		
EPD and its subsidiaries	$ 29,092	$ 25,539
HPC	5,006	5,823
ETE and its subsidiaries	1,382	970
Other	10	10
Total related party receivables	$ 35,490	$ 32,342
Related party payables		
EPD and its subsidiaries	$ 598	$ 1,323
HPC	629	760
ETE and its subsidiaries	10,814	1,245
Other	10	10
Total related party payables	$ 12,051	$ 3,338

9. Segment Information

During the three months ended March 31, 2011, the Partnership renamed its Transportation Segment to Joint Ventures Segment, which represents the Partnership s equity method investments in its two unconsolidated joint ventures, namely HPC and MEP. In addition, the disposition of the east Texas assets in July 2010 impacts the Gathering and Processing segment, as the results of those operations are now presented within discontinued operations and excluded from the segment information table. Accordingly, the Partnership has recast the segment information for the three months ended March 31, 2010.

Gathering and Processing. The Partnership provides wellhead-to-market services to producers of natural gas, which include gathering 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 pipeline-quality natural gas and NGLs to various markets and pipeline systems.

Joint Ventures. The Partnership owns a 49.99 percent general partner interest in HPC, which delivers natural gas from northwest Louisiana to downstream pipelines and markets through the 450-mile Regency Intrastate Gas pipeline system. The Partnership owns a 49.9 percent interest in MEP, which owns approximately 500 miles of natural gas pipeline stretching from southeast Oklahoma through northeast Texas, northern Louisiana and central Mississippi into Alabama.

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Notes to Unaudited Condensed Consolidated Financial Statements (Continued)

Contract Compression. The Partnership owns and operates a fleet of compressors used to provide turn-key natural gas compression services for customers specific systems.

Contract Treating. The Partnership owns and operates a fleet of equipment used to provide treating services, such as carbon dioxide and hydrogen sulfide removal, natural gas cooling, dehydration and BTU management, to natural gas producers and midstream pipeline companies.

Corporate and Others. The Corporate and Others segment comprises a small interstate pipeline and the Partnership s corporate offices.

The Partnership accounts for intersegment revenues as if the revenues were to third parties, exclusive of certain cost of capital charges.

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 is defined as total revenues, including service fees, less cost of sales. In the Contract Compression segment and Contract Treating segment, segment margin is defined as revenues minus direct costs. Management believes segment margin is an important measure because it directly relates to volume, commodity price changes and revenue generating horsepower. Operation and maintenance expenses are a separate measure used by management to evaluate performance of field operations. Direct labor, insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of operation and maintenance expenses. These expenses fluctuate depending on the activities performed during a specific period. The Partnership does not deduct operation and maintenance expenses from total revenues in calculating segment margin because management separately evaluates commodity volume and price changes in segment margin.

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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	Joint Ventures	Contract Compression	Contract Treating (in thousands)	Corporate and Others	Eliminations	Total
External Revenues							
For the three months ended March 31, 2011	$ 265,972	$	$ 38,436	$ 8,433	$ 4,411	$	$ 317,252
For the three months ended March 31, 2010	265,598		34,979		4,208		304,785
Intersegment Revenues							
For the three months ended March 31, 2011			6,553		67	(6,620)	
For the three months ended March 31, 2010			5,332		39	(5,371)	
Cost of Sales							
For the three months ended March 31, 2011	212,172		3,549	1,182	(575)	(67)	216,261
For the three months ended March 31, 2010	214,796		3,281		(767)	(39)	217,271
Segment Margin							
For the three months ended March 31, 2011	53,800		41,440	7,251	5,053	(6,553)	100,991
For the three months ended March 31, 2010	50,802		37,030		5,014	(5,332)	87,514
Operation and Maintenance							
For the three months ended March 31, 2011	22,942		16,504	734	45	(6,553)	33,672
For the three months ended March 31, 2010	20,040		13,778		38	(5,329)	28,527
Depreciation and Amortization							
For the three months ended March 31, 2011	21,457		15,178	2,815	786		40,236
For the three months ended March 31, 2010	15,220		9,207		468		24,895
Income from Unconsolidated Subsidiaries							
For the three months ended March 31, 2011		23,808					23,808
For the three months ended March 31, 2010		7,913					7,913
Assets							
March 31, 2011	1,687,890	1,332,899	1,425,229	219,851	118,752		4,784,621
December 31, 2010	1,724,682	1,351,256	1,411,325	220,584	62,357		4,770,204
Investment in Unconsolidated Subsidiaries							
March 31, 2011		1,332,899					1,332,899
December 31, 2010		1,351,256					1,351,256
Goodwill							
March 31, 2011	313,361		476,428				789,789
December 31, 2010	313,361		476,428				789,789

Expenditures for Long-Lived Assets					
For the three months ended March 31, 2011	29,315	36,498	2,197	623	68,633
For the three months ended March 31, 2010	24,000	11,991		2,474	38,465

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

	Successor Three Months Ended March 31, 2011 (in thousands)	Predecessor Three Months Ended March 31, 2010 (in thousands)
Net income from continuing operations before income taxes	$ 14,273	$ 783
Add (deduct):		
Operation and maintenance	33,672	28,527
General and administrative	18,997	15,403
Loss on assets sales, net	28	284
Depreciation and amortization	40,236	24,895
Income from unconsolidated subsidiaries	(23,808)	(7,913)
Interest expense, net	20,007	20,482
Loss on debt refinancing, net		1,780
Other income and deductions, net	(2,414)	3,273
Total segment margin	$ 100,991	$ 87,514

10. Equity-Based Compensation

The Partnership s LTIP for its employees, directors and consultants authorizes grants up to 3,565,584 common units. LTIP compensation expense of $921,000 and $1,639,000 is recorded in general and administrative expense in the statement of operations for the three months ended March 31, 2011 and March 31, 2010, respectively.

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Notes to Unaudited Condensed Consolidated Financial Statements (Continued)

Common Unit Option. The common unit options activity for the three months ended March 31, 2011 is as follows.

2011				
Common Unit Options	**Units**	**Weighted Average Exercise Price**	**Weighted Average Contractual Term (Years)**	**Aggregate Intrinsic Value *(in thousands)**
Outstanding at the beginning of period	201,950	$ 21.93		
Granted				
Exercised	(26,800)	20.46		$ 179
Forfeited or expired	(300)	23.73		
Outstanding at end of period	174,850	22.15	5.2	912
Exercisable at the end of the period	174,850			912

* 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.

During the three months ended March 31, 2011, the Partnership received $548,000 in proceeds from the exercise of unit options.

Phantom Units. All phantom units granted prior to November 2010 were 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 unit holder return among 20 peer companies. Distributions related to these unvested phantom units will be accrued and paid upon vesting. All phantom units granted after November 2010 were service condition (time-based) grants only with graded vesting over five years. Distributions related to these unvested phantom units will be paid concurrent with the Partnership s distribution for common units.

The following table presents phantom units activity for the three months ended March 31, 2011.

2011		
Phantom Units	**Units**	**Weighted Average Grant Date Fair Value**
Outstanding at the beginning of the period	742,517	$ 23.61
Service condition grants		
Market condition grants		
Vested service condition	(19,647)	20.65
Vested market condition	(6,300)	19.52
Forfeited service condition	(34,670)	25.00
Forfeited market condition	(4,680)	19.52
Total outstanding at end of period	677,220	24.62

The Partnership expects to recognize $13,418,000 of compensation expense related to non-vested phantom units over a period of 4.3 years.

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.

The Partnership s financial assets and liabilities measured at fair value on a recurring basis are derivatives related to interest rate and commodity swaps and embedded derivatives in the Series A Preferred Units. Derivatives related to interest rate and commodity swaps are valued using discounted cash flow techniques. These techniques incorporate Level 1 and Level 2 inputs such as future interest rates and commodity prices. These market inputs are utilized in the discounted cash flow calculation considering the instrument s term, notional amount, discount rate and credit risk and are classified as Level 2 in the hierarchy. Derivatives related to

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Notes to Unaudited Condensed Consolidated Financial Statements (Continued)

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.

	Fair Value Measurment at March 31, 2011			Fair Value Measurment at December 31, 2010		
	Fair Value Total	Significant Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Fair Value Total	Significant Observable Inputs (Level 2)	Unobservable Inputs (Level 3)
	(in thousands)					
Assets						
Commodity Derivatives:						
Natural Gas	$ 1,559	$ 1,559	$	$ 2,481	$ 2,481	$
Natural Gas Liquids				192	192	
Total Assets	$ 1,559	$ 1,559	$	$ 2,673	$ 2,673	$
Liabilities						
Interest Rate Derivatives	$ 2,194	$ 2,194	$	$ 2,584	$ 2,584	$
Commodity Derivatives:						
Natural Gas	162	162		427	427	
Natural Gas Liquids	17,719	17,719		10,684	10,684	
Condensate	7,542	7,542		3,581	3,581	
Embedded Derivatives in Series A Preferred Units	54,448		54,448	57,023		57,023
Total Liabilities	$ 82,065	$ 27,617	$ 54,448	$ 74,299	$ 17,276	$ 57,023

The following table presents the changes in Level 3 derivatives measured on a recurring basis for the three months ended March 31, 2011 and 2010. There were no transfers between Level 2 and Level 3 derivatives for the three months ended March 31, 2011 and 2010.

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
	(in thousands)	
Balance at beginning of the period	$ 57,023	$ 44,594
Net unrealized (gain) loss included in other income and deductions, net	(2,575)	3,385
Balance at the end of period	$ 54,448	$ 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 under which, interest accrues under a floating interest rate structure. Accordingly, the carrying value approximates fair value. The estimated fair value of the senior notes due 2016 based on third party market value quotations as of March 31, 2011 and December 31, 2010 was $285,000,000 and $274,375,000, respectively. The estimated fair value of the senior notes due 2018 based on third party market value quotations as of March 31, 2011 and December 31, 2010 was $639,000,000 and $607,500,000, respectively.

12. Subsequent Events

Formation of ERMH and LDH Acquisition. On May 2, 2011, ERMH, a newly formed joint venture owned 70 percent by ETP and 30 percent by the Partnership, completed its acquisition of all of the membership interest in LDH, a wholly owned subsidiary of Louis Dreyfus Highbridge Energy LLC, for $1,972,000,000 in cash, subject to customary post-closing purchase price adjustments. The Partnership contributed $591,600,000 in cash to ERMH, in exchange of its 30 percent interest. To fund this capital contribution, the Partnership issued 8,500,001 unregistered common units representing limited partnership interests in a private placement with net proceeds of $203,900,000. The remaining portion of the Partnership s capital contribution was funded by additional borrowings under the Partnership s revolving credit facility.

LDH owns and operates an NGL storage, fractionation and transportation business. LDH s storage assets are primarily located in Mont Belvieu, Texas, one of the largest NGL storage, distribution and trading complexes in North America. Its West Texas Pipeline transports NGLs through a 1,066-mile intrastate pipeline system that originates in the Permian Basin in west Texas, passes through the Barnett Shale production area in north Texas and terminates at the Mont Belvieu storage and fractionation complex. LDH also owns and operates fractionation and processing assets located in Louisiana.

The LDH acquisition is expected to significantly expand the Partnership s asset portfolios, adding an NGL platform with storage, transportation and fractionation capabilities. Additionally, this acquisition will provide additional consistent fee-based revenues.

ERMH will be managed by a two-person board of directors, with the Partnership and ETP each having the right to appoint one director. ETP will operate the assets on behalf of ERMH with the former LDH employees.

On May 4, 2011, the Partnership approved an investment of up to $112,500,000 to fund its 30 percent of a ERMH growth capital project for a 100,000 Bbls/d fractionator, the related storage services and interconnectivity infrastructure to be constructed in Mont Belvieu, Texas, which is expected to be completed in early 2013.

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Notes to Unaudited Condensed Consolidated Financial Statements (Continued)

Registration Right Agreement. On May 2, 2011, in connection with the Partnership s issuance of unregistered common units described above, the Partnership also entered into a registration right agreement with the purchasers. Under the registration rights agreements, the Partnership has agreed to file a shelf registration statement no later than June 1, 2011 for the resale of these common units and to use commercially reasonable efforts to cause the shelf registration statement to be declared effective by the SEC no later than July 1, 2011.

Amendment of Revolving Credit Facility. On May 2, 2011, the Partnership amended its Fifth Amended and Restated Credit Agreement to permit the acquisition of equity interests in ERMH and to allow for additional investments in ERMH of up to $150,000,000.

Distribution. On April 26, 2011, the Partnership declared a distribution of $0.445 per outstanding common unit and Series A Preferred Unit, including units equivalent to the General Partner s ownership interest in the Partnership, and a distribution with respect to incentive distribution rights of approximately $1,114,000 payable on May 13, 2011, to unitholders of record at the close of business on May 6, 2011.

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 the notes included elsewhere in this document.

OVERVIEW. We are a growth-oriented publicly-traded Delaware limited partnership formed in 2005 engaged in the gathering, treating, processing, compression and transportation of natural gas and NGLs. We focus on providing midstream services in some of the most prolific natural gas producing regions in the United States, including the Haynseville, Eagle Ford, Barnett, Fayetteville, and Marcellus shales as well as the Permian Delaware basin. Our assets are located in Louisiana, Texas, Arkansas, Pennsylvania, Mississippi, Alabama, and the mid-continent region of the United States, which includes Kansas, Colorado, and Oklahoma.

RECENT DEVELOPMENTS.

Formation of ERMH and LDH Acquisition. On May 2, 2011, ERMH, a newly formed joint venture owned 70 percent by ETP and 30 percent by us, completed its acquisition of all of the membership interest in LDH, a wholly owned subsidiary of Louis Dreyfus Highbridge Energy LLC, for $1,972,000,000 in cash, subject to customary post-closing purchase price adjustments. We contributed $591,600,000 in cash to ERMH, in exchange of our 30 percent interest. To fund this capital contribution, we issued 8,500,001 unregistered common units representing limited partnership interests in a private placement with net proceeds of $203,900,000. The remaining portion of our capital contribution was funded by additional borrowings under our revolving credit facility.

LDH owns and operates an NGL storage, fractionation and transportation business. LDH s storage assets are primarily located in Mont Belvieu, Texas, one of the largest NGL storage, distribution and trading complexes in North America. Its West Texas Pipeline transports NGLs through a 1,066-mile intrastate pipeline system that originates in the Permian Basin in west Texas, passes through the Barnett Shale production area in north Texas and terminates at the Mont Belvieu storage and fractionation complex. LDH also owns and operates fractionation and processing assets located in Louisiana.

The LDH acquisition is expected to significantly expand our asset portfolios, adding an NGL platform with storage, transportation and fractionation capabilities. Additionally, this acquisition will provide additional consistent fee-based revenues.

ERMH will be managed by a two-person board of directors, with us and ETP each having the right to appoint one director. ETP will operate the assets on behalf of ERMH with the former LDH employees.

On May 4, 2011, we approved an investment of up to $112,500,000 to fund our 30 percent of a ERMH growth capital project for a 100,000 Bbls/d fractionator, the related storage services and interconnectivity infrastructure to be constructed in Mont Belvieu, Texas, which is expected to be completed in early 2013.

Registration Right Agreement. On May 2, 2011, in connection with our issuance of unregistered common units described above, we also entered into a registration right agreement with the purchasers. Under the registration rights agreements, we have agreed to file a shelf registration statement no later than June 1, 2011 for the resale of these common units and to use commercially reasonable efforts to cause the shelf registration statement to be declared effective by the SEC no later than July 1, 2011.

Amendment of Revolving Credit Facility. On May 2, 2011, we amended its Fifth Amended and Restated Credit Agreement to permit the acquisition of equity interests in ERMH and to allow for additional investments in ERMH of up to $150,000,000.

OUR OPERATIONS. We divide our operations into five business segments:

- *Gathering and Processing.* We provide wellhead-to-market services to producers of natural gas, which include gathering raw natural gas from the wellhead through gathering systems, processing raw natural gas to separate NGLs and selling or delivering pipeline-quality natural gas and NGLs to various markets and pipeline systems.

- *Joint Ventures.* We own a 49.99 percent general partner interest in HPC, which owns RIGS, a 450-mile intrastate pipeline that delivers natural gas from northwest Louisiana to downstream pipelines and markets. We own a 49.9 percent interest in MEP, which owns an interstate natural gas pipeline with approximately 500 miles stretching from southeast Oklahoma through northeast Texas, northern Louisiana and central Mississippi to an interconnect with the Transcontinental Gas Pipe Line system in Butler, Alabama.

Contract Compression. We own and operate a fleet of compressors used to provide turn-key natural gas compression services for customer specific systems.

Contract Treating. We own and operate a fleet of equipment used to provide treating services, such as carbon dioxide and hydrogen sulfide removal, natural gas cooling, dehydration and BTU management to natural gas producers and midstream pipeline companies.

Corporate and Others. Our Corporate and Others segment comprises a small interstate pipeline and our corporate offices.

HOW WE EVALUATE OUR OPERATIONS. 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.

We do not record segment margin for the Joint Ventures segment because we record our ownership percentages of the net income in HPC and MEP as income from unconsolidated subsidiaries in accordance with the equity method of accounting.

We calculate our Contract Compression segment margin as revenues minus the direct costs, primarily compressor unit repairs, associated with those revenues.

We calculate our Contract Treating segment margin as revenues minus direct costs associated with those revenues.

We calculate total segment margin as the total of segment margin of our five segments, less intersegment eliminations.

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 our revenues and cost of revenues, 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.

Revenue Generating Gallons per Minute (GPM). Revenue generating GPM is the primary driver for revenue growth of our Contract Treating segment. GPM is used as a measure of the treating capacity of an amine plant. Revenue generating GPM is our total GPM under contract less GPM that is not generating revenue.

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;
- non-cash unit based compensation;
- loss (gain) on asset sales, net;

loss on debt refinancing;

other non-cash (income) expense, net; and

the Partnership s interest in adjusted EBITDA from unconsolidated subsidiaries less income from unconsolidated subsidiaries.

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 income (loss) for the Partnership.

	Successor Three Months Ended March 31, 2011 (in thousands)	Predecessor Three Months Ended March 31, 2010 (in thousands)
Reconciliation of Adjusted EBITDA to net cash flows provided by operating activities and to net income (loss)		
Net cash flows provided by operating activities	$ 57,366	$ 32,781
Add (deduct):		
Depreciation and amortization, including debt issuance cost amortization and bond premium amortization	(41,649)	(29,389)
Write-off of debt issuance costs and bond premium		(1,780)
Amortization of excess fair value of unconsolidated subsidiaries	(1,462)	
Income from unconsolidated subsidiaries	25,270	7,913
Derivative valuation change	4,686	(7,182)
Loss on assets sales, net	(28)	(284)
Unit-based compensation expenses	(921)	(1,639)
Trade accounts receivable, accrued revenues and related party receivables	(7,300)	2,017
Other current assets	2,096	(1,091)
Trade accounts payable, accrued cost of gas and liquids, related party payables and deferred revenues	12,145	13,826
Other current liabilities	(10,613)	(12,131)
Distributions received from unconsolidated subsidiaries	(25,270)	(3,526)
Other assets and liabilities	(15)	35
Net income (loss)	14,305	(450)
Add (deduct):		
Interest expense, net	20,007	20,564
Depreciation and amortization	40,236	27,475
Income tax (benefit) expense	(32)	321
EBITDA	74,516	47,910
Add (deduct):		
Non-cash (gain) loss from commodity and embedded derivatives	(4,290)	7,191
Non-cash unit-based compensation	921	1,597
Loss on assets sales, net	28	284
Income from unconsolidated subsidiaries	(23,808)	(7,913)
Partnership s ownership interest in HPC s adjusted EBITDA	19,189	10,675
Partnership s ownership interest in MEP s adjusted EBITDA	25,270	
Loss on debt refinancing, net		1,780
Other expense, net	(89)	90
Adjusted EBITDA	$ 91,737	$ 61,614

The following table presents a reconciliation of net income to EBITDA and adjusted EBITDA for HPC and represents 100 percent of HPC s consolidated results of operations.

	Three Months Ended March 31, 2011	2010
	(in thousands)	
Net income	$ 30,156	$ 18,403

Add:		
Depreciation and amortization	8,082	6,321
Interest expense, net	136	102
EBITDA	$ 38,374	$ 24,826
Add:		
Other expenses, net	11	
Adjusted EBITDA	$ 38,385	$ 24,826

The following table presents a reconciliation of net income to EBITDA and adjusted EBITDA for MEP and represents 100 percent of MEP s consolidated results of operations.

	Three Months Ended March 31, 2011	2010
	(in thousands)	
Net income	$ 20,410	$ 10,948
Add:		
Depreciation and amortization	17,377	16,107
Interest expense, net	12,855	12,558
EBITDA and Adjusted EBITDA	$ 50,642	$ 39,613

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

	Successor Three Months Ended March 31, 2011 (in thousands)	Predecessor Three Months Ended March 31, 2010 (in thousands)
Reconciliation of Adjusted total segment margin to net income (loss)		
Net income (loss)	$ 14,305	$ (450)
Add (deduct):		
Operation and maintenance	33,672	28,527
General and administrative	18,997	15,403
Loss on assets sales, net	28	284
Depreciation and amortization	40,236	24,895
Income from unconsolidated subsidiaries	(23,808)	(7,913)
Interest expense, net	20,007	20,482
Loss on debt refinancing, net		1,780
Other income and deductions, net	(2,414)	3,273
Income tax (benefit) expense	(32)	321
Discontinued operations		912
Total segment margin	100,991	87,514
Add (deduct):		
Non-cash (gain) loss from commodity derivatives	(1,715)	3,806
Adjusted total segment margin	$ 99,276	$ 91,320

RESULTS OF OPERATIONS

Three Months Ended March 31, 2011 vs. Three Months Ended March 31, 2010

	Successor Three Months Ended March 31, 2011 (in thousands)	Predecessor Three Months Ended March 31, 2010	Change	Percent
		(in thousands except percentages)		
Total revenues	$ 317,252	$ 304,785	$ 12,467	4 %
Cost of sales	216,261	217,271	(1,010)	0
Total segment margin (1)	100,991	87,514	13,477	15
Operation and maintenance	33,672	28,527	5,145	18
General and administrative	18,997	15,403	3,594	23
Loss on asset sales, net	28	284	(256)	90
Depreciation and amortization	40,236	24,895	15,341	62
Operating income	8,058	18,405	(10,347)	56
Income from unconsolidated subsidiaries	23,808	7,913	15,895	201
Interest expense, net	(20,007)	(20,482)	475	2
Loss on debt refinancing, net		(1,780)	1,780	100
Other income and deductions, net	2,414	(3,273)	5,687	174
Income from continuing operations before income taxes	14,273	783	13,490	N/M
Income tax (benefit) expense	(32)	321	(353)	110
Net income from continuing operations	$ 14,305	$ 462	$ 13,843	N/M
Discontinued operations		(912)	912	100
Net income (loss)	$ 14,305	$ (450)	$ 14,755	N/M
Net income attributable to noncontrolling interest	(231)	(162)	(69)	43
Net income (loss) attributable to Regency Energy Partners LP	$ 14,074	$ (612)	$ 14,686	N/M %
Gathering and processing segment margin (2)	$ 53,800	$ 50,802	$ 2,998	6%
Add (deduct):				
Non-cash (gain) loss from commodity derivatives	(1,715)	3,806	(5,521)	145
Adjusted gathering and processing segment margin	$ 52,085	$ 54,608	$ (2,523)	5
Contract compression segment margin (3)	41,440	37,030	4,410	12
Contract treating segment margin	7,251		7,251	N/M
Corporate and others segment margin (2)	5,053	5,014	39	1
Intersegment eliminations (3)	(6,553)	(5,332)	(1,221)	23
Adjusted total segment margin	$ 99,276	$ 91,320	$ 7,956	9%

(1) For a reconciliation of segment margin to the most directly comparable financial measure calculated and presented in accordance with GAAP, see the reconciliation provided above.

(2) Segment margin differs from previously disclosed amounts due to the presentation as discontinued operations for the disposition of our east Texas assets, as well as a functional reorganization of our operating segments.

(3) Contract Compression segment margin includes intersegment revenues of $6,553,000 and $5,332,000 for the three months ended March 31, 2011 and March 31, 2010, respectively. These intersegment revenues were eliminated upon consolidation.

N/M Not Meaningful

Net Income (Loss) Attributable to Regency Energy Partners LP. Net income (loss) attributable to Regency Energy Partners LP increased to net income of $14,074,000 in the three months ended March 31, 2011 from a net loss of $612,000 in the three months ended March 31, 2010. The major components of this change were as follows:

- $15,895,000 increase in income from unconsolidated subsidiaries from the acquisition of a 49.9 percent interest in MEP in May 2010, the completion of HPC s expansion projects in early 2010 and our increased general partner interest in HPC from 43 percent as of March 31, 2010 to 49.99 percent as of March 31, 2011;

- $13,477,000 increase in total segment margin primarily from the addition of the Contract Treating segment acquired in September 2010 and Contract Compression segment margin primarily attributable to increased revenue generating horsepower provided to third parties; offset by

- $15,341,000 increase in depreciation and amortization expense primarily related to the completion of various organic growth projects since March 2010 and the increase of property, plant and equipment amounts resulting from the fair value adjustments upon the acquisition of our General Partner in May 2010 resulting the change of control.

Adjusted Total Segment Margin. Adjusted total segment margin increased to $99,276,000 in the three months ended March 31, 2011 from $91,320,000 in the three months ended March 31, 2010. The major components of this increase were as follows:

- Adjusted Gathering and Processing segment margin decreased to $52,085,000 during the three months ended March 31, 2011 from $54,608,000 for the three months ended March 31, 2010 primarily due to lower realized commodity prices. Total Gathering and Processing throughput remained relatively flat (1,006,000 MMBtu/d during the three months ended March 31, 2011 compared to 1,005,000 MMBtu/d during the three months ended March 31, 2010). Total NGL gross production increased to 28,000 Bbls/d during the three months ended March 31, 2011 from 23,000 Bbls/d during the three months ended March 31, 2010;

- Contract Compression segment margin increased to $41,440,000 in the three months ended March 31, 2011 from $37,030,000 in the three months ended March 31, 2010. The increase was primarily attributable to increased revenue generating horsepower provided to third parties and additional contract compression services provided to the Gathering and Processing segment. As of March 31, 2011, our Contract Compression segment had a total revenue generating horsepower of 848,000, including 764,000 horsepower serving external customers and 84,000 serving the Gathering and Processing segment;

- Contract Treating segment margin was $7,251,000 for the three months ended March 31, 2011. We acquired the Contract Treating segment in September, 2010. Revenue generating GPM as of March 31, 2011 was 3,268; and

- Intersegment eliminations increased to $6,553,000 in the three months ended March 31, 2011 from $5,332,000 in the three months ended March 31, 2010. The increase was primarily due to the increased intersegment transactions between the Gathering and Processing and the Contract Compression segments.

Operation and Maintenance. Operation and maintenance expense increased to $33,672,000 in the three months ended March 31, 2011 from $28,527,000 during the three months ended March 31, 2010. The increase was primarily due to the following:

- $1,983,000 increase in labor cost in our Contract Compression segment primarily due to increased bonus accrual as well as increased headcount since March 31, 2010;

- $858,000 increase in consumable products primarily utilized in our Contract Compression segment;

- $734,000 operation and maintenance expense related to our Contract Treating segment that was acquired in September 2010; and

- $514,000 increase in contractor expenses.

General and Administrative. General and administrative expense increased to $18,997,000 in the three months ended March 31, 2011 from $15,403,000 during the three months ended March 31, 2010. The increase was primarily due to the following:

- $2,500,000 of service fees paid to Services Co. in 2011; and

- $695,000 general and administrative expense related to our Contract Treating segment that was acquired in September 2010.

Depreciation and Amortization. Depreciation and amortization expense increased to $40,236,000 in the three months ended March 31, 2011 from $24,895,000 in the three months ended March 31, 2010. This increase was the result of $10,740,000 of additional depreciation and amortization expense due to the completion of various organic growth projects since March 2010. In addition, $4,601,000 of additional depreciation and amortization expense incurred related to the increase of property, plant and equipment amounts resulting from the fair value adjustments upon the acquisition of our General Partner in May 2010 and the resulting change of control. Had the change in control occurred on January 1, 2010, our depreciation and amortization expense for the three months ended March 31, 2010 would have been $29,496,000.

Income from Unconsolidated Subsidiaries. Income from unconsolidated subsidiaries increased to $23,808,000 for the three months ended March 31, 2011 from $7,913,000 for the three months ended March 31, 2010. The schedule set forth below demonstrates the net income for each unconsolidated subsidiary, our share of the net income and the total income from each unconsolidated subsidiary, for the three months ended

March 31, 2011 and 2010, respectively.

	Three Months Ended March 31, 2011			Three Months Ended March 31, 2010		
	HPC	MEP	Total	HPC	MEP	Total
	(in thousands except percentages)			(in thousands except percentages)		
Net income	$ 30,156	$ 20,410	$ 50,566	$ 18,403	$ 10,948	$ 29,351
Interest percentage	49.99%	49.9%	N/M	43%	N/A	N/M
Share of unconsolidated subsidiaries net income	15,075	10,195	25,270	7,913		7,913
Less: Amortization of excess fair value of unconsolidated subsidiaries	(1,462)		(1,462)			
Income from unconsolidated subsidiaries	$ 13,613	$ 10,195	$ 23,808	$ 7,913	$	$ 7,913

N/A We acquired 49.9 percent interest in MEP in May 2010.

N/M Not Meaningful

HPC s net income increased to $30,156,000 for the three months ended March 31, 2011 from $18,403,000 for the three months ended March 31, 2010, primarily due to the completion of HPC s expansion projects in January 2010, which increased capacity from 0.9 Bcf/d to 2.1 Bcf/d.

MEP s net income increased to $20,410,000 for the three months ended March 31, 2011 from $10,948,000 for the three months ended March 31, 2010, primarily due to the completion of MEP s expansion projects in June 2010, which increased capacity from 1.5 Bcf/d to 1.8 Bcf/d.

Other Income and Deductions, Net. Other income and deductions, net increased to a gain of $2,414,000 in the three months ended March 31, 2011 from a net loss of $3,273,000 in the three months ended March 31, 2010, primarily due to the non-cash mark-to-market adjustment in the embedded derivatives related to the Series A Preferred Units issued in September 2009.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

In addition to the information set forth in this report, further information regarding our critical accounting policies and estimates is included in Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2010.

See Item 1, Note 1 - Organization and Summary of Significant Accounting Policies of this report for the description of our push-down accounting in connection with the acquisition of our General Partner in May 2010 and the resulting change in control, together with the description of recently issued accounting standards.

OTHER MATTERS

Information regarding our commitments and contingencies is included in Note 6 Commitments and Contingencies to the condensed consolidated financial statements included in Item 1 of this report.

IRS Audits. The Closing Conference concluding the IRS examination of the Partnership s 2007 and 2008 tax returns was held on April 19, 2011. The IRS proposed various adjustments to the Partnership s tax returns which the Partnership anticipates appealing. It is not known whether such adjustments would be material, or how such adjustments would affect unitholders.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

We expect our sources of liquidity to include:

- cash generated from operations;
- borrowings under our revolving credit facility;
- distributions received from unconsolidated subsidiaries;
- debt offerings; and
- issuance of additional partnership units.

We expect our base growth capital expenditures to be $253,000,000 in 2011, which includes $155,000,000 for the Gathering and Processing segment, mostly in south Texas, $78,000,000 for the Contract Compression segment, $12,000,000 for the Contract Treating segment, and $8,000,000 for the Corporate and Others segment. In addition, we expect our maintenance capital expenditures to be $14,000,000 in 2011, excluding maintenance capital expenditures related to our joint venture interests. We may revise the timing of these expenditures as necessary to adapt to economic conditions.

HPC s 100 percent growth capital expenditure for 2011 is expected to be $42,000,000 and is expected to be funded under its revolving credit facility.

Working Capital. 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 and Contract Treating segments record 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 deficit decreased to $30,664,000 at March 31, 2011 from $35,145,000 at December 31, 2010. This decrease was primarily due to the following factors:

- an increase in cash and cash equivalents of $15,324,000 generated primarily from cash flows from operations;

- a decrease of $7,543,000 in trade payables and receivables, net primarily due to the timing of our cash receipts and disbursements; and partially offset by

- an increase of $11,109,000 in derivative liabilities and assets, net primarily due to increase in commodity prices and new trades entered into since year end; and

- an increase in other current assets and liabilities, net of $8,497,000 primarily due to the interest accrual on our senior notes, interest is paid semi-annually in December and June.

Cash Flows from Operating Activities. Net cash flows provided by operating activities increased to $57,366,000 in the three months ended March 31, 2011 from $32,781,000 in the three months ended March 31, 2010. The increase in cash flows from operating activities was primarily due to an increase in segment margin and income from unconsolidated subsidiaries primarily due to the acquisition of MEP in May 2010.

Cash Flows used in Investing Activities. Net cash flows used in investing activities increased to $51,732,000 in the three months ended March 31, 2011 from $48,043,000 in the three months ended March 31, 2010, primarily related to capital expenditures for growth projects.

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. In the three months ended March 31, 2011, we incurred $61,878,000 of growth capital expenditures. Growth capital expenditures for the three months ended March 31, 2011, primarily related to $33,597,000 for the fabrication of new compressor packages for our Contract Compression segment, $25,916,000 for organic growth projects for our Gathering and Processing segment and $2,365,000 for the fabrication of new treating plants for our Contract Treating 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, 2011, we incurred $3,433,000 of maintenance capital expenditures.

Cash Flows from Financing Activities. Net cash flows provided by financing activities slightly increased to $9,690,000 in the three months ended March 31, 2011 from $9,521,000 during the same period in 2010.

Capital Resources. On May 2, 2011, we issued 8,500,001 unregistered common units representing limited partnership interests in a private placement with net proceeds of $203,900,000, to partially fund our capital contribution to ERMH. The remaining capital contribution of $387,700,000 was funded through additional borrowings under our revolving credit facility.

Amendment of Revolving Credit Facility. On May 2, 2011, we amended our Fifth Amended and Restated Credit Agreement to permit the acquisition of equity interest in ERMH and to allow for additional investments in ERMH of up to $150,000,000.

Additional Investment in ERMH. On May 4, 2011, we approved an investment of up to $112,500,000 to fund our 30 percent of a ERMH growth capital project for a 100,000 Bbls/d fractionator, the related storage services and interconnectivity infrastructure to be constructed in Mont Belvieu, Texas, which is expected to be completed in early 2013.

Cash Distributions from Unconsolidated Subsidiaries. During the three months ended March 31, 2011, we received cash distributions of $25,437,000 and $16,728,000 from MEP and HPC, respectively.

Item 3. Quantitative and Qualitative Disclosure about Market Risk

Risk and Accounting Policies. We are exposed to market risks associated with commodity prices, counterparty credit, and interest rates. Management and the board of directors of our General Partner have established comprehensive risk management policies and procedures to monitor and manage these market risks. Our General Partner is responsible for delegation of transaction authority levels, and the Audit and Risk Management Committee of our General Partner is responsible for the oversight of credit risk and commodity price risk, including monitoring exposure limits. The Audit and Risk Management Committee receives regular briefings on positions and exposures, credit exposures and overall risk management in the context of market activities.

Commodity Price Risk. We are a net seller of NGLs, 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 forces. Our profitability and cash flow are affected by the inherent volatility of these commodities, which could adversely affect our cash available for distribution and 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. Speculative positions with derivative contracts are prohibited under our risk management policy.

We execute natural gas, NGLs and WTI trades on a periodic basis to hedge our anticipated equity exposure. Our swap contracts settle 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 executed swap contracts that will settle against NGLs, condensate and natural gas prices for our expected exposure in the approximate percentages set forth below.

	As of March 31, 2011	
	2011	2012
NGLs	80%	42%
Condensate	86%	55%
Natural gas	60%	18%

The following table sets forth certain information regarding our hedges for natural gas, NGLs, and WTI, outstanding at March 31, 2011. The relevant index price that we pay for NGLs 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. The fair value of our outstanding trades is determined using a discounted cash flow model based on third-party prices and readily available market information.

Period	Underlying	Notional Volume/ Amount	We Pay	We Receive Weighted Average Price	Fair Value Asset/(Liability) (in thousands)	Effect of Hypothetical Change in Index* (in thousands)
April 2011-September 2012	Ethane	758 (MBbls)	Index	$0.49($/gallon)	$ (2,990)	$ 1,841
April 2011-December 2012	Propane	438 (MBbls)	Index	1.03($/gallon)	(6,189)	2,528
April 2011-December 2012	Normal Butane	267 (MBbls)	Index	1.41($/gallon)	(4,652)	2,047
April 2011-December 2012	Natural Gasoline	147 (MBbls)	Index	1.83($/gallon)	(3,888)	1,522
April 2011-December 2012	West Texas Intermediate Crude	370 (MBbls)	Index	86.82($/Bbl)	(7,542)	3,976
April 2011-June 2012	Natural gas	3,110,000 (MMBtu)	Index	5.15($/MMBtu)	1,397	1,461
April 2011-April 2012	Interest Rate	$ 250,000,000	1.325%	Three-month LIBOR	(2,194)	2,500
				Total Fair Value	$ (26,058)	

* Price risk sensitivities were calculated by assuming a theoretical 10 percent change, increase or decrease, in prices regardless of the term or the historical relationships between the contractual price of the instrument and the underlying commodity price. Interest rate sensitivity assumes a 100 basis point increase or decrease in the LIBOR yield curve. The price sensitivity results are presented in absolute terms.

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 Principal 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 Principal Financial Officer of our managing general partner, concluded that our disclosure controls and procedures were effective as of March 31, 2011 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. Effective January 1, 2011, the Partnership has begun to integrate certain business functions under a shared services agreement with Services Co. As of March 31, 2011, no significant changes have been made to the Partnership s accounting systems; however, certain controls and procedures have been changed to conform to the existing controls of the shared services provider. Additional changes, including the transition of the Partnership s accounting systems, are expected to be completed during the second quarter of 2011. None of these changes are in response to any identified deficiency or weakness in our internal control over financial reporting.

There were no other changes in our internal controls over financial reporting that have materially affected, or are reasonably likely to affect, our 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

Our recently announced transactions present several risks. Many of those risks are similar to the risks associated with our existing businesses, as we have previously disclosed. However, certain of those risks represent new risks related to our business or existing risks that have become more significant. The following risk factors should be read in conjunction with our risk factors described in Part I, Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2010.

Risks Related to Our Business

We do not control, and therefore may not be able to cause or prevent certain actions by, certain of our joint ventures.

Certain of our joint ventures have their own governing boards, and we may not control all of the decisions of those boards. Consequently, it may be difficult or impossible for us to cause the joint venture entity to take actions that we believe would be in our or the joint venture s best interests. Likewise, we may be unable to prevent actions of the joint venture.

The profitability of certain activities in our NGL and refined products storage business, our NGL transportation business and our off-gas processing and fractionating business are largely dependent upon market demand for NGLs and refined products, which has been volatile, and competition in the market place, both of which are factors that are beyond our control.

Our NGL and refined products storage revenues are primarily derived from fixed capacity arrangements between us and our customers. However, a portion of our revenues are derived from fungible storage and throughput arrangements, under which our revenues are more dependent upon demand for storage from our customers. Demand for these services may fluctuate as a result of changes in commodity prices. Our NGL and refined products storage assets are primarily located in the Mont Belvieu area, which is a significant storage distribution and trading complex with multiple industry participants, any one of which could compete for the business of our existing and potential customers. Any loss of business from existing customers or our inability to attract new customers could have an adverse effect on our results of operations.

Revenues from our NGL transportation systems are exposed to risks due to fluctuations in demand for transportation as a result of unfavorable commodity prices and competition from nearby pipelines. We receive substantially all of our transportation revenues through dedicated contracts under which the customer agrees to deliver the total output from particular processing plants that are connected only to our transportation system. We may not be able to renew these contracts or execute new customer contracts on favorable terms if NGL prices decline and demand for our transportation services decreases. Any loss of existing customers due to decreased demand for our services or competition from other transportation service providers could have a negative impact on our revenues and have an adverse effect on our results of operations.

Revenues from our off-gas processing and fractionating system in south Louisiana are exposed to risks due to the low concentration of suppliers near our facilities and the possibility that connected refineries may not provide us with sufficient off-gas for processing at our facilities. The connected refineries may also experience outages due to maintenance issues and severe weather, such as hurricanes. We receive revenues primarily through customer agreements that are a combination of keep-whole and percent-of-proceeds arrangements, as well as from transportation and fractionation fees. Consequently, a large portion of our off-gas processing and fractionation revenues are exposed to risks due to fluctuations in commodity prices. In addition, a decline in NGL prices could cause a decrease in demand for our off-gas processing and fractionation services and could have an adverse effect on our results of operations.

The markets and prices for natural gas and NGLs depend upon factors beyond our control. These factors include demand for oil, natural gas and NGLs, which fluctuate with changes in market and economic conditions, and other factors, including:

- the impact of weather on the demand for oil, natural gas and NGLs;
- the level of domestic oil and natural gas production;
- the availability of imported oil, natural gas and NGLs;
- actions taken by foreign oil and gas producing nations;
- the availability of local transportation systems;
- the price, availability and marketing of competitive fuels;
- the demand for electricity;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation.

Certain of our assets may become subject to regulation.

Intrastate transportation of NGLs is largely regulated by the state in which such transportation takes place. The 1,066-mile West Texas Pipeline, which we acquired as part the LDH acquisition, transports NGLs within the state of Texas and is subject to regulation by the Texas Railroad Commission (TRRC). This NGL transportation system offers services pursuant to an intrastate transportation tariff on file with the TRRC. Such services must be provided in a manner that is just, reasonable and non-discriminatory. We believe that this NGL system does not provide interstate service and that it is thus not subject to FERC jurisdiction under the Interstate Commerce Act and the Energy Policy Act of 1992. We cannot guarantee that the jurisdictional status of this NGL pipeline system will remain unchanged, however. Should it be found jurisdictional, the FERC s rate-making methodologies may, among other things, delay the use of rates that reflect increased costs and subject us to potentially burdensome and expensive operational, reporting and other requirements. Any of the foregoing could adversely affect revenues and cash flow related to these assets.

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 2.5

	Purchase Agreement, dated as of March 22, 2011, by and among ETP-Regency Midstream Holdings, LLC, LDH Energy Asset Holdings LLC, Louis Dreyfus Highbridge Energy LLC and, for the limited purposes set forth therein, Energy Transfer Partners, L.P. and Regency Energy Partners LP. (Incorporated by reference to Exhibit 2.1 to our Form 8-K/A dated March 25, 2011.)
Exhibit 4.5	Registration Rights Agreement, dated May 2, 2011. (Incorporated by reference to Exhibit 4.1 to our Form 8-K dated May 2, 2011.)
Exhibit 10.33	Assumption, Contribution and Indemnification Agreement, dated as of March 22, 2011, between Energy Transfer Partners, L.P. and Regency Energy Partners LP. (Incorporated by reference to Exhibit 10.2 to our Form 8-K/A dated March 25, 2011.)
Exhibit 10.34	Common Unit Purchase Agreement, dated March 23, 2011, by and among Regency Energy Partners LP and the purchasers named therein. (Incorporated by reference to Exhibit 10.1 to our Form 8-K dated March 28, 2011.)
Exhibit 10.35	Amended and Restated Limited Liability Company Agreement of ETP-Regency Midstream Holdings, LLC, dated May 2, 2011. (Incorporated by reference to Exhibit 10.1 to our Form 8-K dated May 2, 2011.)
Exhibit 10.36	Amendment Agreement No. 2 to the Fifth Amended and Restated Credit Agreement, dated May 2, 2011. (Incorporated by reference to Exhibit 10.2 to our Form 8-K dated May 2, 2011.)
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 Principal Financial Officer
Exhibit 32.1	Section 1350 Certifications of Chief Executive Officer
Exhibit 32.2	Section 1350 Certifications of Principal Financial Officer
Exhibit 101.INS	XBRL Instance Document
Exhibit 101.SCH	XBRL Taxonomy Extension Schemat
Exhibit 101.CAL	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.DEF	XBRL Taxonomy Extension Definition Linkbase
Exhibit 101.LAB	XBRL Taxonomy Extension Label Linkbase
Exhibit 101.PRE	XBRL Taxonomy Extension Presentation Linkbase

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 5, 2011

/s/ A. TROY STURROCK
A. Troy Sturrock

Vice President, Controller and Principal Accounting Officer

(Duly Authorized Officer)