Regency Energy Partners LP
Form 10-Q
August 08, 2011
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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 June 30, 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	**16-1731691**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
2001 BRYAN STREET, SUITE 3700 DALLAS, TX	**75201**
(Address of principal executive offices)	**(Zip Code)**

(214) 750-1771

(Registrant s telephone number, including area code)

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. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

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

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

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

The issuer had 145,843,942 common units outstanding as of July 29, 2011.

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Regency Energy Partners LP

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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
/d	Per day
AOCI	Accumulated Other Comprehensive Income
Bbls	Barrels
Bcf	One billion cubic feet
BTU	A unit of energy needed to raise the temperature of one pound of water by one degree Fahrenheit
ETC	Energy Transfer Company, the name assumed by La Grange Acquisition, L.P. for conducting business and shared services, a wholly-owned subsidiary of ETP
ETE	Energy Transfer Equity, L.P.
ETE GP	ETE GP Acquirer LLC
ETP	Energy Transfer Partners, L.P.
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 EFS	General Electric Energy Financial Services, 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 partnerships
GPM	Gallons per minute
GP Seller	Regency GP Acquirer, L.P.
HPC	RIGS Haynesville Partnership Co., a general partnership in which the Partnership owns a 49.99% interest and its 100% owned subsidiary, Regency Intrastate Gas LP
IDRs	Incentive Distribution Rights
IRS	Internal Revenue Service
LDH	LDH Energy Asset Holdings LLC
LIBOR	London Interbank Offered Rate
Lone Star	Lone Star NGL LLC, a joint venture that is 70% owned by ETP and 30% owned by the Partnership
LTIP	Long-Term Incentive Plan
MEP	Midcontinent Express Pipeline LLC, a joint venture in which the Partnership owns a 49.9% interest
MMbtu	One million BTUs
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
WTI	West Texas Intermediate Crude

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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 indemnification cleanup liabilities and to clean up any hazardous materials release on satisfactory terms;

- 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 and our Quarterly Report on Form 10-Q for the quarter ended March 31, 2011.

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.

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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.

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Regency Energy Partners LP

Condensed Consolidated Balance Sheets

(in thousands)

(unaudited)

	June 30, 2011	December 31, 2010
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 3,105	$ 9,400
Trade accounts receivable, net of allowance of $465 and $297	36,740	35,212
Accrued revenues	85,195	74,017
Related party receivables	34,587	32,342
Derivative assets	1,075	2,650
Other current assets	8,772	7,384
Total current assets	169,474	161,005
Property, Plant and Equipment:		
Gathering and transmission systems	591,915	543,286
Compression equipment	825,944	812,428
Gas plants and buildings	178,134	185,741
Other property, plant and equipment	122,276	81,295
Construction-in-progress	154,739	97,439
Total property, plant and equipment	1,873,008	1,720,189
Less accumulated depreciation	(123,755)	(59,971)
Property, plant and equipment, net	1,749,253	1,660,218
Other Assets:		
Investment in unconsolidated affiliates	1,920,412	1,351,256
Long-term derivative assets	366	23
Other, net of accumulated amortization of debt issuance costs of $6,621 and $3,326	43,316	37,758
Total other assets	1,964,094	1,389,037
Intangible Assets and Goodwill:		
Intangible assets, net of accumulated amortization of $30,220 and $15,584	755,519	770,155
Goodwill	789,789	789,789
Total intangible assets and goodwill	1,545,308	1,559,944
TOTAL ASSETS	$ 5,428,129	$ 4,770,204
LIABILITIES AND PARTNERS CAPITAL AND NONCONTROLLING INTEREST		
Current Liabilities:		
Trade accounts payable	$ 37,035	$ 50,208
Accrued cost of gas and liquids	81,906	80,756
Related party payables	37,185	3,338
Deferred revenues, including related party amounts of $41 and $8,765	17,348	25,257
Derivative liabilities	20,679	13,172
Other current liabilities	30,280	23,419

Total current liabilities	224,433	196,150
Long-term derivative liabilities	53,033	61,127
Other long-term liabilities	6,046	6,521
Long-term debt, net	1,685,613	1,141,061
Commitments and contingencies		
Series A Preferred Units, redemption amount of $84,549 and $83,891	71,040	70,943
Partners capital and noncontrolling interest:		
Common units	3,042,153	2,940,732
General partner interest	331,166	333,077
Accumulated other comprehensive loss	(17,571)	(11,099)
Total partners capital	3,355,748	3,262,710
Noncontrolling interest	32,216	31,692
Total partners capital and noncontrolling interest	3,387,964	3,294,402
TOTAL LIABILITIES AND PARTNERS CAPITAL AND NONCONTROLLING INTEREST	$ 5,428,129	$ 4,770,204

See accompanying notes to condensed consolidated financial statements

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Regency Energy Partners LP

Condensed Consolidated Statements of Operations

(in thousands except unit data and per unit data)

(unaudited)

	Successor		Predecessor
	Three Months Ended June 30, 2011	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from April 1, 2010 to May 25, 2010
REVENUES:			
Gas sales, including related party amounts of $6,161, $447 and $0	$ 132,800	$ 47,241	$ 87,193
NGL sales, including related party amounts of $77,048, $18,054 and $0	138,088	26,040	62,997
Gathering, transportation and other fees, including related party amounts of $5,254, $2,086 and $3,680	81,817	22,571	45,041
Net realized and unrealized (loss) gain from derivatives	(7,542)	(130)	223
Other, including related party amounts of $2,924, $0 and $0	11,335	1,258	4,811
Total revenues	356,498	96,980	200,265
OPERATING COSTS AND EXPENSES:			
Cost of sales, including related party amounts of $7,807, $2,281 and $3,198	259,475	70,174	140,507
Operation and maintenance	33,996	10,402	19,315
General and administrative, including related party amounts of $4,224, $833 and $0	17,551	7,104	21,809
Loss on asset sales, net	153	10	19
Depreciation and amortization	40,503	10,545	16,889
Total operating costs and expenses	351,678	98,235	198,539
OPERATING INCOME (LOSS):	4,820	(1,255)	1,726
Income from unconsolidated affiliates	32,167	8,121	7,959
Interest expense, net	(24,689)	(8,081)	(14,059)
Other income and deductions, net	2,641	(3,521)	(624)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	14,939	(4,736)	(4,998)
Income tax expense	102	245	83
INCOME (LOSS) FROM CONTINUING OPERATIONS	$ 14,837	$ (4,981)	$ (5,081)
DISCONTINUED OPERATIONS:			
Net income from operations of east Texas assets		86	585
NET INCOME (LOSS)	$ 14,837	$ (4,895)	$ (4,496)
Net income attributable to noncontrolling interest	(293)	(29)	(244)
NET INCOME (LOSS) ATTRIBUTABLE TO REGENCY ENERGY PARTNERS LP	$ 14,544	$ (4,924)	$ (4,740)
Amounts attributable to Series A Preferred Units	1,995	668	1,335

General partner s interest, including IDRs	1,550	803	
Limited partners interest in net income (loss)	$ 10,999	$ (6,395)	$ (6,075)
Income (loss) from continuing operations per common unit:			
Amount allocated to common units	$ 10,999	$ (6,479)	$ (6,660)
Weighted average number of common units outstanding	142,937,163	119,600,652	92,832,219
Basic income (loss) from continuing operations per common unit	$ 0.08	$ (0.05)	$ (0.07)
Diluted income (loss) from continuing operations per common unit	$ 0.07	$ (0.05)	$ (0.07)
Distributions per unit	$ 0.45	$ 0.445	$
Basic and diluted income from discontinued operations per common unit	$	$	$ 0.01
Basic and diluted net income (loss) per common unit:			
Amount allocated to common units	$ 10,999	$ (6,395)	$ (6,075)
Basic net income (loss) per common unit	$ 0.08	$ (0.05)	$ (0.07)
Diluted net income (loss) per common unit	$ 0.07	$ (0.05)	$ (0.07)

See accompanying notes to condensed consolidated financial statements

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Regency Energy Partners LP

Condensed Consolidated Statements of Operations

(in thousands except unit data and per unit data)

(unaudited)

	Successor		Predecessor
	Six Months Ended June 30, 2011	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from January 1, 2010 to May 25, 2010
REVENUES:			
Gas sales, including related party amounts of $11,639, $447 and $0	$ 242,887	$ 47,241	$ 228,097
NGL sales, including related party amounts of $150,041, $18,054 and $0	256,339	26,040	152,803
Gathering, transportation and other fees, including related party amounts of $11,470, $2,086 and $12,200	163,653	22,571	114,526
Net realized and unrealized loss from derivatives	(9,256)	(130)	(716)
Other, including related party amounts of $4,790, $0 and $0	20,127	1,258	10,340
Total revenues	673,750	96,980	505,050
OPERATING COSTS AND EXPENSES:			
Cost of sales, including related party amounts of $11,021, $2,281 and $6,564	475,736	70,174	357,778
Operation and maintenance	67,556	10,402	47,842
General and administrative, including related party amounts of $8,129, $833 and $0	36,660	7,104	37,212
Loss on asset sales, net	181	10	303
Depreciation and amortization	80,739	10,545	41,784
Total operating costs and expenses	660,872	98,235	484,919
OPERATING INCOME (LOSS):	12,878	(1,255)	20,131
Income from unconsolidated affiliates	55,975	8,121	15,872
Interest expense, net	(44,696)	(8,081)	(34,541)
Loss on debt refinancing, net			(1,780)
Other income and deductions, net	5,055	(3,521)	(3,897)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	29,212	(4,736)	(4,215)
Income tax expense	70	245	404
INCOME (LOSS) FROM CONTINUING OPERATIONS	$ 29,142	$ (4,981)	$ (4,619)
DISCONTINUED OPERATIONS:			
Net income (loss) from operations of east Texas assets		86	(327)
NET INCOME (LOSS)	$ 29,142	$ (4,895)	$ (4,946)
Net income attributable to noncontrolling interest	(524)	(29)	(406)
NET INCOME (LOSS) ATTRIBUTABLE TO REGENCY ENERGY PARTNERS LP	$ 28,618	$ (4,924)	$ (5,352)

Amounts attributable to Series A Preferred Units		3,988		668		3,336
General partner s interest, including IDRs		2,842		803		662
Amount allocated to non-vested common units						(79)
Limited partners interest in net income (loss)	$	21,788	$	(6,395)	$	(9,271)
Income (loss) from continuing operations per common unit:						
Amount allocated to common units	$	21,788	$	(6,479)	$	(8,966)
Weighted average number of common units outstanding		140,135,219		119,600,652		92,788,319
Basic income (loss) from continuing operations per common unit	$	0.16	$	(0.05)	$	(0.10)
Diluted income (loss) from continuing operations per common unit	$	0.14	$	(0.05)	$	(0.10)
Distributions per unit	$	0.895	$	0.445	$	0.445
Basic and diluted income from discontinued operations per common unit	$		$		$	
Basic and diluted net income (loss) per common unit:						
Amount allocated to common units	$	21,788	$	(6,395)	$	(9,271)
Basic net income (loss) per common unit	$	0.16	$	(0.05)	$	(0.10)
Diluted net income (loss) per common unit	$	0.14	$	(0.05)	$	(0.10)

See accompanying notes to condensed consolidated financial statements

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Regency Energy Partners LP

Condensed Consolidated Statements of Comprehensive Income (Loss)

(in thousands)

(unaudited)

	Successor		Predecessor
	Three Months Ended June 30, 2011	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from April 1, 2010 to May 25, 2010
Net income (loss)	$ 14,837	$ (4,895)	$ (4,496)
Net cash flow hedge amounts reclassified to earnings	5,565		(512)
Change in fair value of cash flow hedges	1,530		8,649
Comprehensive income (loss)	21,932	(4,895)	3,641
Comprehensive income attributable to noncontrolling interest	293	29	244
Comprehensive income (loss) attributable to Regency Energy Partners LP	$ 21,639	$ (4,924)	$ 3,397

	Successor		Predecessor
	Six Months Ended June 30, 2011	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from January 1, 2010 to May 25, 2010
Net income (loss)	$ 29,142	$ (4,895)	$ (4,946)
Net cash flow hedge amounts reclassified to earnings	8,994		2,145
Net change in fair value of cash flow hedges	(15,466)		18,486
Comprehensive income (loss)	22,670	(4,895)	15,685
Comprehensive income attributable to noncontrolling interest	524	29	406
Comprehensive income (loss) attributable to Regency Energy Partners LP	$ 22,146	$ (4,924)	$ 15,279

See accompanying notes to condensed consolidated financial statements

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Regency Energy Partners LP

Condensed Consolidated Statements of Cash Flows

(in thousands)

(unaudited)

	Successor		Predecessor
	Six Months Ended June 30, 2011	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from January 1, 2010 to May 25, 2010
OPERATING ACTIVITIES:			
Net income (loss)	$ 29,142	$ (4,895)	$ (4,946)
Adjustments to reconcile net income (loss) to net cash flows provided by (used in) operating activities:			
Depreciation and amortization, including debt issuance cost amortization and bond premium amortization	83,587	11,330	49,363
Write-off of debt issuance costs			1,780
Amortization of excess fair value of unconsolidated affiliates	2,923	365	
Equity in earnings of unconsolidated affiliates	(58,898)	(8,486)	(15,872)
Derivative valuation changes	(5,826)	6,921	12,004
Loss on asset sales, net	181	10	303
Unit-based compensation expenses	1,747	137	12,070
Cash flow changes in current assets and liabilities:			
Trade accounts receivable, accrued revenues and related party receivables	(8,847)	13,843	(11,272)
Other current assets	964	585	2,516
Trade accounts payable, accrued cost of gas and liquids, related party payables and deferred revenues	28,577	(15,460)	8,649
Other current liabilities	(2,764)	(20,497)	22,614
Distributions received from unconsolidated affiliates	50,510		12,446
Cash flow changes in other assets and liabilities	(182)	(60)	(234)
Net cash flows provided by (used in) operating activities	121,114	(16,207)	89,421
INVESTING ACTIVITIES:			
Capital expenditures	(172,236)	(20,875)	(63,787)
Capital contributions to unconsolidated affiliates	(591,681)	(38,922)	(20,210)
Distribution in excess of earnings of unconsolidated affiliates	27,990		
Acquisitions, net of cash received		12,848	(75,114)
Proceeds from asset sales	4,003	14	10,661
Net cash flows used in investing activities	(731,924)	(46,935)	(148,450)
FINANCING ACTIVITIES:			
Net borrowings under revolving credit facility	45,000	37,000	199,008
Proceeds from issuance of senior notes	500,000		
Debt issuance costs	(9,936)	(132)	(15,728)
Partner contributions		7,436	
Partner distributions	(131,106)		(86,078)
Disposition of assets between entities under common control in excess of historical cost	25		(16,973)
Distributions to noncontrolling interest			(1,135)

Proceeds from issuance of common units under LTIP, net of tax withholding	506	150	(4,874)
Proceeds from common unit issuances, net of issuance costs	203,917		(89)
Distributions to Series A Preferred Units	(3,891)		(1,945)
Net cash flows provided by financing activities	604,515	44,454	72,186
Net change in cash and cash equivalents	(6,295)	(18,688)	13,157
Cash and cash equivalents at beginning of period	9,400	22,984	9,827
Cash and cash equivalents at end of period	$ 3,105	$ 4,296	$ 22,984
Supplemental cash flow information:			
Non-cash capital expenditures	$ 14,598	$ 16,159	$ 18,051
Issuance of common units for an acquisition		584,436	
Deemed contribution from acquisition of assets between entities under common control		17,152	
Contribution receivable		12,288	

See accompanying notes to condensed consolidated financial statements

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Regency Energy Partners LP

Condensed Consolidated Statement of Partners Capital and Noncontrolling Interest

(dollar amounts in thousands)

(unaudited)

	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
Private common unit offering, net of costs	8,500,001	203,917				203,917
Issuance of common units under LTIP, net of forfeitures and tax withholding	56,405	506				506
Unit-based compensation expenses		1,747				1,747
Disposition of assets between entities under common control in excess of historical cost			25			25
Partner distributions		(126,404)	(4,702)			(131,106)
Accrued distributions to phantom units		(209)				(209)
Net income		25,776	2,842		524	29,142
Distributions to Series A Preferred Units		(3,815)	(76)			(3,891)
Accretion of Series A Preferred Units		(97)				(97)
Net cash flow hedge amounts reclassified to earnings				8,994		8,994
Change in fair value of cash flow hedges				(15,466)		(15,466)
Balance - June 30, 2011	145,837,742	$ 3,042,153	$ 331,166	$ (17,571)	$ 32,216	$ 3,387,964

See accompanying notes to condensed consolidated financial statements

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Regency Energy Partners LP

Notes to Condensed Consolidated Financial Statements

(Tabular dollar amounts, except per unit data, are in thousands)

(unaudited)

1. Organization and Summary of Significant Accounting Policies

Organization. The unaudited condensed consolidated financial statements presented herein contain the results of Regency Energy Partners LP and its subsidiaries. The Partnership and its subsidiaries are engaged in the business of gathering, 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 reclassified to conform 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 made 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.

Quarterly Distributions of Available Cash. Following are distributions declared and/or paid by the Partnership subsequent to December 31, 2010:

Quarter Ended	Record Date	Payment Date	Cash Distributions (per common unit)
December 31, 2010	February 7, 2011	February 14, 2011	$ 0.445
March 31, 2011	May 6, 2011	May 13, 2011	$ 0.445
June 30, 2011	August 5, 2011	August 12, 2011	$ 0.45

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2. Income (Loss) per Limited Partner Unit

The following tables provide a reconciliation of the numerator and denominator of the basic and diluted earnings per unit computations for the three and six months ended June 30, 2011. For the three and six months ended June 30, 2010, including successor and predecessor periods, diluted earnings per unit equaled basic earnings per unit because all instruments were antidilutive.

	Three Months Ended June 30, 2011		
	Income (Numerator)	Units (Denominator)	Per-Unit Amount
Basic income from continuing operations per unit			
Limited Partners interest	$ 10,999	142,937,163	$ 0.08
Effect of Dilutive Securities			
Common unit options		25,826	
Phantom units *		237,747	
Series A Preferred Units	(955)	4,614,250	
Diluted income from continuing operations per unit	$ 10,044	147,814,986	$ 0.07

	Six Months Ended June 30, 2011		
	Income (Numerator)	Units (Denominator)	Per-Unit Amount
Basic income from continuing operations per unit			
Limited Partners interest	$ 21,788	140,135,219	$ 0.16
Effect of Dilutive Securities			
Common unit options		28,403	
Phantom units *		231,251	
Series A Preferred Units	(1,537)	4,584,192	
Diluted income from continuing operations per unit	$ 20,251	144,979,065	$ 0.14

* 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		Predecessor
	Three Months Ended June 30, 2011	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from April 1, 2010 to May 25, 2010
Restricted (non-vested) common units			356,954
Common unit options		290,150	290,150
Phantom units *		322,750	351,345
Series A Preferred Units		4,584,192	4,584,192

	Successor		Predecessor
	Six Months Ended June	Period from Acquisition (May 26, 2010) to	Period from January 1, 2010 to May 25, 2010

	30, 2011	June 30, 2010
Restricted (non-vested) common units		396,918
Common unit options	290,150	298,400
Phantom units *	322,750	369,346
Series A Preferred Units	4,584,192	4,584,192

* Amount assumes maximum conversion rate for market condition awards.

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3. Investment in Unconsolidated Affiliates

Lone Star. On May 2, 2011, Lone Star, a newly formed joint venture that is owned 70% by ETP and 30% 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 $1.97 billion in cash, subject to customary post-closing purchase price adjustments. The Partnership contributed $591.7 million in cash to Lone Star, in exchange for its 30% interest. To fund a portion of this capital contribution, the Partnership issued 8,500,001 common units representing limited partnership interests with net proceeds of $203.9 million. These units were issued in a private placement conducted in accordance with the exemption from the registration requirement of the Securities Act of 1933, as amended, under section 4(2) thereof. These units were subsequently registered with the SEC. The remaining portion of the Partnership s capital contribution was funded by additional borrowings under its revolving credit facility.

Lone Star owns and operates an NGL storage, fractionation and transportation business. Lone Star s storage assets are primarily located in Mont Belvieu, Texas and its West Texas Pipeline transports NGLs through an 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. Lone Star also owns and operates fractionation and processing assets located in Louisiana.

Lone Star is managed by a two-person board of directors, with the Partnership and ETP each having the right to appoint one director, and is operated by ETP. As of June 30, 2011, the carrying value of the Partnership s interest in Lone Star was $600.1 million. Amounts recorded with respect to Lone Star for the period ended June 30, 2011 are summarized in the table below:

	Period from Initial Contribution (May 2, 2011) to June 30, 2011
Contributions to Lone Star	$ 591,681
Partnership s share of Lone Star s net income	8,388

The summarized income statement information of Lone Star (on a 100% basis) is disclosed below:

	Period from Initial Contribution (May 2, 2011) to June 30, 2011
Total revenues	$ 98,820
Operating income	28,143
Net income	27,958

Upon the completion of Lone Star s acquisition of all of the membership interests in LDH, Lone Star recorded the assets and liabilities of LDH at fair value. As a result, no basis difference currently exists between the Partnership s investment in Lone Star and the Partnership s proportionate share of the underlying equity in net assets of Lone Star, and the Partnership s equity of earnings for Lone Star reflects its proportionate share of Lone Star s net income.

HPC. The Partnership owns a 49.99% general partner interest in HPC. As of June 30, 2011 and December 31, 2010, the carrying value of the Partnership s interest in HPC was $691.2 million and $698.8 million, respectively. Amounts recorded with respect to HPC for the three and six months ended June 30, 2011 and 2010, including successor and predecessor periods, are summarized in the tables below:

	Successor		Predecessor
	Three Months Ended June 30, 2011	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from April 1, 2010 to May 25, 2010
Contributions to HPC	$	$	$ 20,210
Distributions received from HPC	18,113		8,920
Partnership s share of HPC s net income	15,130	4,460	7,959
Amortization of excess fair value of investment in HPC	1,461	365	

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	Successor		Predecessor
	Six Months Ended June 30, 2011	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from January 1, 2010 to May 25, 2010
Contributions to HPC	$	$	$ 20,210
Distributions received from HPC	34,841		12,446
Partnership s share of HPC s net income	30,205	4,460	15,872
Amortization of excess fair value of investment in HPC	2,923	365	

The summarized income statement information of HPC (on a 100% basis) is disclosed below:

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010
Total revenues	$ 48,585	$ 44,375
Operating income	30,515	25,950
Net income	30,265	25,871

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Total revenues	$ 97,234	$ 79,564
Operating income	60,842	44,416
Net income	60,421	44,274

MEP. The Partnership owns a 49.9% interest in MEP. As of June 30, 2011 and December 31, 2010, the carrying value of the Partnership s interest in MEP was $629.1 million and $652.5 million, respectively. Amounts recorded with respect to MEP for the three and six months ended June 30, 2011 and 2010 are summarized in the tables below:

	Three Months Ended June 30, 2011	Period from Acquisition (May 26, 2010) to June 30, 2010
Distributions received from MEP	$ 18,222	$
Partnership s share of MEP s net income	10,110	4,026

	Six Months Ended June 30, 2011	Period from Acquisition (May 26, 2010) to June 30, 2010
Distributions received from MEP	$ 43,659	$
Partnership s share of MEP s net income	20,305	4,026

The summarized income statement information of MEP (on a 100% basis) is disclosed below:

	Three Months Ended June 30, 2011	Period from Acquisition (May 26, 2010) to June 30, 2010
Total revenues	$ 64,943	$ 21,269

Operating income	33,190	11,499
Net income	20,276	8,068

	Six Months Ended June 30, 2011	Period from Acquisition (May 26, 2010) to June 30, 2010
Total revenues	$ 129,767	$ 21,269
Operating income	66,455	11,499
Net income	40,686	8,068

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.

At June 30, 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 June 30, 2011, the Partnership had $330 million of outstanding borrowings exposed to variable interest rate risk. In April 2010, the Partnership entered into two-year interest rate swaps related to $250 million of borrowings under its revolving credit facility, effectively locking the base rate, exclusive of applicable margins, for these borrowings at 1.325% 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, and utilizes master netting 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 June 30, 2011 would be $1.4 million which would be reduced in full due to the netting feature. The Partnership has elected to present assets and liabilities under master netting agreements gross on the condensed consolidated balance sheets.

Embedded Derivatives. The Series A Preferred Units contain embedded derivatives which are required to be bifurcated and accounted for separately, such as the holders conversion option and the Partnership s call option. These embedded derivatives are accounted for using mark-to-market accounting. The Partnership does not expect the embedded derivatives to affect its cash flows.

Quantitative Disclosures. The Partnership expects to reclassify $16.4 million of net hedging losses to revenues from accumulated other comprehensive loss in the next 12 months.

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The Partnership s derivative assets and liabilities, including credit risk adjustments, as of June 30, 2011 and December 31, 2010 are detailed below:

	Assets		Liabilities	
	June 30, 2011	December 31, 2010	June 30, 2011	December 31, 2010
Derivatives designated as cash flow hedges				
Current amounts				
Commodity contracts	$ 1,075	$ 2,650	$ 18,827	$ 11,421
Long-term amounts				
Commodity contracts	366	23	1,535	3,271
Total cash flow hedging instruments	1,441	2,673	20,362	14,692
Derivatives not designated as cash flow hedges				
Current amounts				
Interest rate contracts			1,852	1,751
Long-term amounts				
Interest rate contracts				833
Embedded derivatives in Series A Preferred Units			51,498	57,023
Total derivatives not designated as cash flow hedges			53,350	59,607
Total derivatives	$ 1,441	$ 2,673	$ 73,712	$ 74,299

The Partnership s statement of operations for the three months ended June 30, 2011 and 2010 were impacted by derivative instruments activities as follows:

		Successor		Predecessor
		Three Months Ended June 30, 2011	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from April 1, 2010 to May 25, 2010
	Location of Gain/(Loss) Recognized in Income	**Change in Value Recognized in AOCI on Derivatives (Effective Portion)**		
Derivatives in cash flow hedging relationships:				
Commodity derivatives	Revenues	$ 1,530	$	$ 7,428
	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	$ (7,133)	$	$ (709)
	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	$ (362)	$	$ (301)

	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) from Designation Amortized from AOCI into Income		
Derivatives not designated in a hedging relationship:				
Commodity derivatives	Revenues	$	$	$ 1,221

	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 (credit risk adjustment)	Revenues	$ (47)	$ (824)	$ 12
Interest rate swap derivatives	Interest expense, net	(228)	(1,715)	(824)
Embedded derivatives	Other income & deductions	2,950	(3,606)	(654)
		$ 2,675	$ (6,145)	$ (1,466)

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The Partnership s statement of operations for the six months ended June 30, 2011 and 2010 were impacted by derivative instruments activities as follows:

		Successor		Predecessor
		Six Months Ended June 30, 2011	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from January 1, 2010 to May 25, 2010
	Location of Gain/(Loss) Recognized in Income	**Change in Value Recognized in AOCI on Derivatives (Effective Portion)**		
Derivatives in cash flow hedging relationships:				
Commodity derivatives	Revenues	$ (15,466)	$	$ 14,371
	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	$ (8,994)	$	$ (5,200)
Interest rate swap derivatives	Interest expense			(1,060)
		$ (8,994)	$	$ (6,260)
	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	$ (274)	$	$ (799)
	Location of Gain/(Loss) Recognized in Income	**Amount of Gain/(Loss) from Designation Amortized from AOCI into Income**		
Derivatives not designated in a hedging relationship:				
Commodity derivatives	Revenues	$	$	$ 4,115
	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 (credit risk adjustment)	Revenues	$ 12	$ (824)	$ 1,247
Interest rate swap derivatives	Interest expense, net	(487)	(1,715)	(824)
Embedded derivatives	Other income & deductions	5,525	(3,606)	(4,039)
		$ 5,050	$ (6,145)	$ (3,616)

5. Long-term Debt

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

	June 30, 2011	December 31, 2010
Senior notes	$ 1,355,613	$ 856,061
Revolving loans	330,000	285,000
Total	1,685,613	1,141,061
Less: current portion		
Long-term debt	$ 1,685,613	$ 1,141,061
Availability under revolving credit facility:		
Total credit facility limit	$ 900,000	$ 900,000
Revolving loans	(330,000)	(285,000)
Letters of credit	(11,015)	(16,015)
Total available	$ 558,985	$ 598,985

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Scheduled maturities of long-term debt at June 30, 2011 are as follows:

Years Ending December 31,	Amount
2011 (remainder)	$
2012	
2013	
2014	330,000
2015	
Thereafter	1,350,000*
Total	$ 1,680,000

* Excludes an unamortized premium of $5.6 million as of June 30, 2011.

Revolving Credit Facility. The Partnership s $900 million revolving credit facility expires on June 15, 2014. The revolving credit facility and guarantees are senior to the Partnership s and each 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 June 30, 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 3.25% and 3.92%, respectively, during the six months ended June 30, 2011 and 2010.

On May 2, 2011, the Partnership amended its Fifth Amended and Restated Credit Agreement to permit the acquisition of equity interests in Lone Star and to allow for additional investments in Lone Star of up to $150 million.

Senior Notes. In May 2011, the Partnership and Finance Corp. issued $500 million in senior notes that mature on July 15, 2021 (2021 Notes). The senior notes bear interest at 6.5% payable semi-annually in arrears on January 15 and July 15, commencing January 15, 2012. The Partnership capitalized $9.8 million in debt issuance costs that will be amortized to interest expense, net over the term of the senior notes. The proceeds were used to repay borrowings outstanding under the Partnership s revolving credit facility.

At any time prior to July 15, 2014, the Partnership may redeem up to 35% of the senior notes at a price equal to 106.5% plus accrued interest. Beginning on July 15 of the years indicated below, the Partnership may redeem all or part of the 2021 Notes at the redemption prices, expressed as percentages of the principal amount, set forth below:

July 15 of year ending:	Percentage of Redemption
2016	103.250%
2017	102.167%
2018	101.083%
2019 and thereafter at 100%	100.000%

Upon a change of control, as defined in the indenture, followed by a rating decline within 90 days, each holder of the 2021 Notes will be entitled to require the Partnership to purchase all or a portion of its notes at a purchase price of 101% plus accrued interest and liquidated damages, if any. The Partnership s ability to purchase the notes upon a change of control will be limited by the terms of our debt agreements, including the Partnership s revolving credit facility.

The 2021 Notes contain various covenants that limit, among other things, the Partnership s ability, and the ability of certain of its subsidiaries, to:

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

If the 2021 Notes achieve investment grade ratings by both Moody s and S&P and no default or event of default has occurred and is continuing, the Partnership will no longer be subject to many of the foregoing covenants. At June 30, 2011, the Partnership was in compliance with these covenants.

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Finance Corp., co-issuer for all of the Partnership s senior notes, has no operations and will not have revenues other than as may be incidental. Since the Partnership has no independent operations, the guarantees are fully unconditional and joint and several of its existing unconsolidated subsidiaries, except for one minor subsidiary, and the Partnership has not included condensed consolidated financial information of guarantors of the senior notes.

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.

7. Series A Preferred Units

On September 2, 2009, the Partnership issued 4,371,586 Series A Preferred Units. As of June 30, 2011, the Series A Preferred Units were convertible to 4,620,152 common units, and if outstanding, are mandatorily redeemable on September 2, 2029 for $80 million 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 unit 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 six months ended June 30, 2011:

	Units	Amount
Balance at January 1, 2011	4,371,586	$ 70,943
Accretion to redemption value		97
Ending balance as of June 30, 2011	4,371,586	$ 71,040*

* This amount will be accreted to $80 million plus any accrued and unpaid distributions by deducting amounts from partners capital over the remaining period until the mandatory redemption date of September 2, 2029.

8. Related Party Transactions

As of June 30, 2011 and December 31, 2010, details of the Partnership s related party receivables and related party payables were as follows:

	June 30, 2011	December 31, 2010
Related party receivables		
EPD and its subsidiaries	$ 18,649	$ 25,539
HPC	7,846	5,823
ETE and its subsidiaries	6,669	970
Other	1,423	10

Total related party receivables	$ 34,587	$ 32,342
Related party payables		
EPD and its subsidiaries	$ 754	$ 1,323
HPC	1,966	760
ETE and its subsidiaries	34,443	1,245
Other	22	10
Total related party payables	$ 37,185	$ 3,338

Transactions with ETE and its subsidiaries. Under a May 26, 2010 service 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 million, 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. Also, the Partnership, together with Regency GP LP and RGS entered into an operation and service agreement (the Operations Agreement) with ETC. Under the Operations Agreement, ETC will perform certain operations, maintenance and related services reasonably required to operate and maintain certain facilities owned by the Partnership. Pursuant to the Operations Agreement, the Partnership will reimburse ETC for actual costs and expenses incurred in connection with the provision of these services based on an annual budget agreed-upon by both parties. The Operations Agreement has an initial term of one year and automatically renews on a year-to-year basis upon expiration of the initial term.

The total fees related to these service contracts were $4.2 million and $8.1 million for the three and six months ended June 30, 2011, and for the period from the acquisition, May 26, 2010, to June 30, 2010 was $0.8 million.

In conjunction with distributions by the Partnership to the limited and general partner interests, ETE received cash distributions of $14.1 million and $28.1 million during the three and six months ended June 30, 2011.

The Partnership s Contract Compression segment provides contract compression services to subsidiaries of ETP and records revenue 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 $5.5 million and $6.3 million for the three and six months ended June 30, 2011, respectively. As these transactions are between entities under common control, partners capital was increased by $25 thousand, which represented a deemed contribution of the excess sales price over the carrying amounts.

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 six months ended June 30, 2011, reimbursements of $24.6 million and $8.6 million were recorded to the General Partner and to ETP, respectively, in the Partnership s financial statements as operating expenses or general and administrative expenses, as appropriate. For the six months ended June 30, 2010, reimbursements of $5.7 million, $10.4 million and $31.1 million to the General Partner were recorded, respectively, during the periods from May 26, 2010 to June 30, 2010, from April 1, 2010 to May 25, 2010 and from January 1, 2010 to May 25, 2010 in the Partnership s financial statements as operating expenses or general and administrative expenses.

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 and six months ended June 30, 2011, from May 26, 2010 to June 30, 2010, from April 1, 2010 to May 25, 2010 and from January 1, 2010 to May 25, 2010, the related party general and administrative expenses reimbursed to the Partnership were $4.2 million, $8.4 million, $1.4 million, $2.8 million and $6.9 million, 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 in 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 a portion 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.

9. Segment Information

During the six months ended June 30, 2011, the Partnership changed the name of the Transportation segment to Joint Ventures, which represents the Partnership s equity method investments in its three unconsolidated joint ventures: HPC, MEP and Lone Star. 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 corresponding periods in 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% 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% 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. The Partnership has a 30% interest in Lone Star, an entity owning a diverse set of midstream energy assets including pipelines, storage and processing facilities located in the states of Texas, Mississippi and Louisiana.

Contract Compression. The Partnership owns and operates a fleet of compressors used to provide turn-key natural gas compression services for customer 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 10 mile 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 and the Corporate and Others segments 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 less 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. We do not record segment margin for the Joint Ventures segment because we record our ownership percentages of the net income in HPC, MEP and Lone Star as income from unconsolidated affiliates in accordance with the equity method of accounting.

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Results for each period, together with amounts related to balance sheets for each segment, are shown below:

	Successor		Predecessor
	Three Months Ended June 30, 2011	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from April 1, 2010 to May 25, 2010
External Revenues			
Gathering and Processing	$ 303,203	$ 83,778	$ 173,206
Joint Ventures			
Contract Compression	38,072	12,054	23,992
Contract Treating	10,842		
Corporate and Others	4,381	1,148	3,067
Eliminations			
Total	$ 356,498	$ 96,980	$ 200,265
Intersegment Revenues			
Gathering and Processing	$	$	$
Joint Ventures			
Contract Compression	2,917	1,998	3,794
Contract Treating			
Corporate and Others	110	22	52
Eliminations	(3,027)	(2,020)	(3,846)
Total	$	$	$
Segment Margin			
Gathering and Processing	$ 50,495	$ 14,373	$ 35,195
Joint Ventures			
Contract Compression	36,973	12,488	25,326
Contract Treating	7,701		
Corporate and Others	4,762	1,943	3,031
Eliminations	(2,908)	(1,998)	(3,794)
Total	$ 97,023	$ 26,806	$ 59,758
Operation and Maintenance			
Gathering and Processing	$ 19,528	$ 7,463	$ 13,390
Joint Ventures			
Contract Compression	16,310	4,924	9,698
Contract Treating	675		
Corporate and Others	397	13	21
Eliminations	(2,914)	(1,998)	(3,794)
Total	$ 33,996	$ 10,402	$ 19,315

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	Successor		Predecessor
	Six Months Ended June 30, 2011	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from January 1, 2010 to May 25, 2010
External Revenues			
Gathering and Processing	$ 569,175	$ 83,778	$ 438,804
Joint Ventures			
Contract Compression	76,508	12,054	58,971
Contract Treating	19,275		
Corporate and Others	8,792	1,148	7,275
Eliminations			
Total	$ 673,750	$ 96,980	$ 505,050
Intersegment Revenues			
Gathering and Processing	$	$	$
Joint Ventures			
Contract Compression	9,470	1,998	9,126
Contract Treating			
Corporate and Others	177	22	91
Eliminations	(9,647)	(2,020)	(9,217)
Total	$	$	$
Segment Margin			
Gathering and Processing	$ 104,295	$ 14,373	$ 85,997
Joint Ventures			
Contract Compression	78,413	12,488	62,356
Contract Treating	14,952		
Corporate and Others	9,815	1,943	8,045
Eliminations	(9,461)	(1,998)	(9,126)
Total	$ 198,014	$ 26,806	$ 147,272
Operation and Maintenance			
Gathering and Processing	$ 42,470	$ 7,463	$ 33,430
Joint Ventures			
Contract Compression	32,702	4,924	23,476
Contract Treating	1,409		
Corporate and Others	442	13	59
Eliminations	(9,467)	(1,998)	(9,123)
Total	$ 67,556	$ 10,402	$ 47,842

The tables below provide a reconciliation of total segment margin to income from continuing operations before income taxes:

	Successor		Predecessor
	Three Months Ended June 30, 2011	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from April 1, 2010 to May 25, 2010

Total segment margin	$ 97,023	$ 26,806	$ 59,758
Operation and maintenance	(33,996)	(10,402)	(19,315)
General and administrative	(17,551)	(7,104)	(21,809)
Loss on assets sales, net	(153)	(10)	(19)
Depreciation and amortization	(40,503)	(10,545)	(16,889)
Income from unconsolidated affiliates	32,167	8,121	7,959
Interest expense, net	(24,689)	(8,081)	(14,059)
Other income and deductions, net	2,641	(3,521)	(624)
Income (loss) from continuing operations before income taxes	$ 14,939	$ (4,736)	$ (4,998)

	Successor		Predecessor
	Six Months Ended June 30, 2011	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from January 1, 2010 to May 25, 2010
Total segment margin	$ 198,014	$ 26,806	$ 147,272
Operation and maintenance	(67,556)	(10,402)	(47,842)
General and administrative	(36,660)	(7,104)	(37,212)
Loss on assets sales, net	(181)	(10)	(303)
Depreciation and amortization	(80,739)	(10,545)	(41,784)
Income from unconsolidated affiliates	55,975	8,121	15,872
Interest expense, net	(44,696)	(8,081)	(34,541)
Loss on debt refinancing, net			(1,780)
Other income and deductions, net	5,055	(3,521)	(3,897)
Income (loss) from continuing operations before income taxes	$ 29,212	$ (4,736)	$ (4,215)

The table below provides a listing of assets reflected in the consolidated balance sheet for each segment:

	June 30, 2011	December 31, 2010
Gathering and Processing	$ 1,800,025	$ 1,724,682
Joint Ventures	1,920,412	1,351,256
Contract Compression	1,409,239	1,411,325
Contract Treating	221,110	220,584
Corporate and Others	77,343	62,357
Total	$ 5,428,129	$ 4,770,204

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 $0.8 million, $1.7 million, $0.1 million, $10.4 million and $12.1 million is recorded in general and administrative expense in the statement of operations for the three and six months ended June 30, 2011 and for the periods from May 26, 2010 to June 30, 2010, April 1, 2010 to May 25, 2010 and from January 1, 2010 to May 25, 2010, respectively.

Common Unit Options. The common unit options activity during the six months ended June 30, 2011 is as follows:

	2011			
Common Unit Options	**Units**	**Weighted Average Exercise Price**	**Weighted Average Contractual Term (Years)**	**Aggregate Intrinsic Value ***
Outstanding at the beginning of period (January 1, 2011)	201,950	$ 21.93		
Granted				
Exercised	(32,100)	20.21		$ 204
Forfeited or expired	(3,800)	26.39		
Outstanding at end of period	166,050	22.13	4.9	652
Exercisable at the end of the period (June 30, 2011)	166,050			652

* 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 six months ended June 30, 2011, the Partnership received $0.7 million 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 unitholder 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 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.

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The following table presents phantom units activity for the six months ended June 30, 2011:

	2011	
Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period (January 1, 2011)	742,517	$ 23.61
Service condition grants	68,745	26.21
Market condition grants		
Vested service condition	(20,980)	20.69
Vested market condition	(8,550)	19.52
Forfeited service condition	(56,900)	25.07
Forfeited market condition	(6,660)	19.52
Total outstanding at end of period (June 30, 2011)	718,172	24.77

The Partnership expects to recognize $13 million of compensation expense related to non-vested phantom units over a period of 4.2 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 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 following table presents the Partnership s derivative assets and liabilities measured at fair value on a recurring basis:

	Fair Value Measurements at June 30, 2011			Fair Value Measurements 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)

Assets:						
Commodity Derivatives:						
Natural Gas	$ 1,374	$ 1,374	$	$ 2,481	$ 2,481	$
NGLs	67	67		192	192	
Total Assets	$ 1,441	$ 1,441	$	$ 2,673	$ 2,673	$
Liabilities:						
Interest Rate Derivatives	$ 1,852	$ 1,852	$	$ 2,584	$ 2,584	$
Commodity Derivatives:						
Natural Gas				427	427	
NGLs	16,711	16,711		10,684	10,684	
Condensate	3,651	3,651		3,581	3,581	
Embedded Derivatives in Series A Preferred Units	51,498		51,498	57,023		57,023
Total Liabilities	$ 73,712	$ 22,214	$ 51,498	$ 74,299	$ 17,276	$ 57,023

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The following table presents the changes in Level 3 derivatives measured on a recurring basis for the six months ended June 30, 2011. There were no transfers between the fair value hierarchy levels for the six months ended June 30, 2011.

Balance at January 1, 2011	$ 57,023
Net unrealized gain included in other income and deductions, net	(5,525)
Balance at June 30, 2011	$ 51,498

The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to their short-term maturities. 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 2016 Notes, based on third party market value quotations as of June 30, 2011 and December 31, 2010 was $279.4 million and $274.4 million, respectively. The estimated fair value of the 2018 Notes, based on third party market value quotations as of June 30, 2011 and December 31, 2010 was $624.0 million and $607.5 million, respectively. The estimated fair value of the 2021 Notes, based on third party market value quotations as of June 30, 2011 was $506.3 million.

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Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations
(Tabular dollar amounts are in thousands)

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 Haynesville, 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

Eagle Ford Expansion. In June 2011, we entered into agreements to provide gas and condensate gathering services for a producer in the Eagle Ford Shale and to construct facilities to perform these services, including a wellhead gathering system, at an expected cost of approximately $450 million. The expansion will be owned and operated by us and will tie into our existing gathering system. In addition, we have purchased certain existing midstream assets located in the Eagle Ford Shale as part of this expansion. The expansion is scheduled for completion by 2014.

Lone Star Expansion. In May 2011, Lone Star announced a construction project of a 100,000 Bbls/d fractionator and related storage services and interconnectivity infrastructure to be constructed in Mont Belvieu, Texas, which is expected to be completed in early 2013. Our estimated capital expenditures for this project are approximately $110 million.

In June 2011, Lone Star announced it would construct an approximate 530-mile natural gas liquids pipeline that extends from Winkler County in west Texas to a processing plant in Jackson County, Texas. This pipeline will have a minimum capacity of approximately 130,000 Bbls/d with the potential to upsize the pipeline capacity depending on ongoing negotiations. Our estimated capital expenditures for this project are $210 million. In addition, Lone Star has secured capacity on ETP s recently announced NGL pipeline from Jackson County to Mont Belvieu, Texas.

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% 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% 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. We own a 30% interest in Lone Star, an entity owning a diverse set of midstream energy assets including pipelines, storage and processing facilities located in the states of Texas, Mississippi and Louisiana.

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 expense, EBITDA, and adjusted EBITDA on a segment and company-wide basis.

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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 for the Gathering and Processing and the Corporate and Others segments, as revenues, including service fees, less cost of sales. We calculate our revenues generated from operations less 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, MEP and Lone Star as income from unconsolidated affiliates in accordance with the equity method of accounting.

We calculate our Contract Compression segment margin as revenues minus 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 summation 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 the total horsepower that our Contract Compression segment owns and operates for external customers. It does not include horsepower under contract that is not generating revenue or 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, net, income tax expense, net 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;

net income attributable to noncontrolling interest; and

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

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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		Predecessor
	Six Months Ended June 30, 2011	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from January 1, 2010 to May 25, 2010
Reconciliation of Adjusted EBITDA to net cash flows provided by (used in) operating activities and net income (loss)			
Net cash flows provided by (used in) operating activities	$ 121,114	$ (16,207)	$ 89,421
Add (deduct):			
Depreciation and amortization, including debt issuance cost amortization and bond premium amortization	(83,587)	(11,330)	(49,363)
Write-off of debt issuance costs			(1,780)
Amortization of excess fair value of unconsolidated affiliates	(2,923)	(365)	
Income from unconsolidated affiliates	58,898	8,486	15,872
Derivative valuation change	5,826	(6,921)	(12,004)
Loss on assets sales, net	(181)	(10)	(303)
Unit-based compensation expenses	(1,747)	(137)	(12,070)
Trade accounts receivable, accrued revenues and related party receivables	8,847	(13,843)	11,272
Other current assets	(964)	(585)	(2,516)
Trade accounts payable, accrued cost of gas and liquids, related party payables and deferred revenues	(28,577)	15,460	(8,649)
Other current liabilities	2,764	20,497	(22,614)
Distributions received from unconsolidated affiliates	(50,510)		(12,446)

Other assets and liabilities	182	60	234
Net income (loss)	29,142	(4,895)	(4,946)
Add (deduct):			
Interest expense, net	44,696	8,109	34,679
Depreciation and amortization expense	80,739	10,995	46,084
Income tax expense	70	245	404
EBITDA	154,647	14,454	76,221
Add (deduct):			
Non-cash (gain) loss from commodity and embedded derivatives	(5,093)	5,856	11,189
Non-cash unit-based compensation expense	1,796	113	11,925
Loss on assets sales, net	181	10	303
Income from unconsolidated affiliates, net of amortization	(55,975)	(8,121)	(15,872)
Partnership s ownership interest in HPC s adjusted EBITDA	38,775	5,824	21,184
Partnership s ownership interest in MEP s adjusted EBITDA	50,513	8,424	
Partnership s ownership interest in Lone Star s adjusted EBITDA	10,584		
Loss on debt refinancing, net			1,780
Other (income) expense, net	(235)	191	2,064
Adjusted EBITDA	$ 195,193	$ 26,751	$ 108,794

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

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Net income	$ 60,421	$ 44,274
Add:		
Depreciation and amortization	16,746	14,421
Interest expense, net	387	201
EBITDA	$ 77,554	$ 58,896
Add:		
Other expenses, net	11	12
Adjusted EBITDA	$ 77,565	$ 58,908

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

	Six Months Ended June 30, 2011	Period from Acquisition (May 26, 2010) to June 30, 2010
Net income	$ 40,686	$ 8,068
Add:		
Depreciation and amortization	34,775	5,383
Interest expense, net	25,768	3,431
EBITDA and Adjusted EBITDA	$ 101,229	$ 16,882

The following table presents a reconciliation of net income to EBITDA and adjusted EBITDA for Lone Star and represents 100% of Lone Star s consolidated results of operations:

	Period from Initial Contribution (May 2, 2011) to June 30, 2011
Net income	$ 27,958
Add:	
Depreciation and amortization	7,139
Other expenses, net	185
EBITDA and Adjusted EBITDA	$ 35,282

The following tables present a reconciliation of total segment margin and adjusted total segment margin to net income (loss) for the three and six month periods ended June 30, 2011 for the Partnership:

	Successor		Predecessor
	Three Months Ended June 30, 2011	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from April 1, 2010 to May 25, 2010
Net income (loss)	$ 14,837	$ (4,895)	$ (4,496)
Add (deduct):			
Operation and maintenance	33,996	10,402	19,315
General and administrative	17,551	7,104	21,809
Loss on assets sales, net	153	10	19
Depreciation and amortization	40,503	10,545	16,889
Income from unconsolidated affiliates	(32,167)	(8,121)	(7,959)
Interest expense, net	24,689	8,081	14,059
Other income and deductions, net	(2,641)	3,521	624
Income tax expense	102	245	83
Discontinued operations		(86)	(585)
Total segment margin	97,023	26,806	59,758
Add:			
Non-cash loss from commodity derivatives	2,147	2,250	3,344
Adjusted total segment margin	$ 99,170	$ 29,056	$ 63,102

	Successor		Predecessor
	Six Months Ended June 30, 2011	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from January 1, 2010 to May 25, 2010
Net income (loss)	$ 29,142	$ (4,895)	$ (4,946)
Add (deduct):			
Operation and maintenance	67,556	10,402	47,842
General and administrative	36,660	7,104	37,212
Loss on assets sales, net	181	10	303
Depreciation and amortization	80,739	10,545	41,784
Income from unconsolidated affiliates	(55,975)	(8,121)	(15,872)
Interest expense, net	44,696	8,081	34,541
Loss on debt refinancing, net			1,780
Other income and deductions, net	(5,055)	3,521	3,897
Income tax expense	70	245	404
Discontinued operations		(86)	327
Total segment margin	198,014	26,806	147,272
Add:			
Non-cash loss from commodity derivatives	432	2,250	7,150
Adjusted total segment margin	$ 198,446	$ 29,056	$ 154,422

RESULTS OF OPERATIONS

Three Months Ended June 30, 2011 vs. Combined Three Months Ended June 30, 2010

	Successor		Predecessor			
	Three Months Ended June 30, 2011	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from April 1, 2010 to May 25, 2010	Combined Three Months Ended June 30, 2010	Change	Percent
Total revenues	$ 356,498	$ 96,980	$ 200,265	$ 297,245	$ 59,253	20%
Cost of sales	259,475	70,174	140,507	210,681	(48,794)	23%
Total segment margin (1)	97,023	26,806	59,758	86,564	10,459	12%
Operation and maintenance	33,996	10,402	19,315	29,717	(4,279)	14%
General and administrative	17,551	7,104	21,809	28,913	11,362	39%
Loss on asset sales, net	153	10	19	29	(124)	428%
Depreciation and amortization	40,503	10,545	16,889	27,434	(13,069)	48%
Operating income (loss)	4,820	(1,255)	1,726	471	4,349	923%
Income from unconsolidated affiliates	32,167	8,121	7,959	16,080	16,087	100%
Interest expense, net	(24,689)	(8,081)	(14,059)	(22,140)	(2,549)	12%
Other income and deductions, net	2,641	(3,521)	(624)	(4,145)	6,786	164%
Income (loss) from continuing operations before income taxes	14,939	(4,736)	(4,998)	(9,734)	24,673	253%
Income tax expense	102	245	83	328	226	69%
Net income (loss) from continuing operations	14,837	(4,981)	(5,081)	(10,062)	24,899	247%

Discontinued operations		86	585	671	(671)	100%
Net income (loss)	14,837	(4,895)	(4,496)	(9,391)	24,228	258%
Net income attributable to noncontrolling interest	(293)	(29)	(244)	(273)	(20)	7%
Net income (loss) attributable to Regency Energy Partners LP	$ 14,544	$ (4,924)	$ (4,740)	$ (9,664)	$ 24,208	250%
Gathering and processing segment margin (2)	$ 50,495	$ 14,373	$ 35,195	$ 49,568	$ 927	2%
Non-cash loss from commodity derivatives	2,147	2,250	3,344	5,594	(3,447)	62%
Adjusted gathering and processing segment margin	52,642	16,623	38,539	55,162	(2,520)	5%
Contract compression segment margin (3)	36,973	12,488	25,326	37,814	(841)	2%
Contract treating segment margin	7,701				7,701	100%
Corporate and others segment margin (2)	4,762	1,943	3,031	4,974	(212)	4%
Intersegment eliminations (3)	(2,908)	(1,998)	(3,794)	(5,792)	2,884	50%
Adjusted total segment margin	$ 99,170	$ 29,056	$ 63,102	$ 92,158	$ 7,012	8%

(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 \$2.9 million and \$5.8 million for the three months ended June 30, 2011 and June 30, 2010, respectively. These intersegment revenues were eliminated upon consolidation.

Net Income (Loss) Attributable to Regency Energy Partners LP. Our income increased to $14.5 million for the three months ended June 30, 2011 from a net loss of $9.7 million for the combined three months ended June 30, 2010. The major components of this change were as follows:

$16.1 million increase in income from unconsolidated affiliates from the acquisition of a 30% interest in Lone Star in May 2011 and the acquisition of a 49.9% interest in MEP in May 2010;

$11.4 million decrease in general and administrative expense related to the vesting of the outstanding restricted and phantom units that occurred in the second quarter of 2010 upon the change in control resulting from the acquisition of our General Partner;

$10.5 million increase in total segment margin primarily from the addition of the Contract Treating segment acquired in September 2010; offset by

$13.1 million increase in depreciation and amortization expense primarily related to the completion of various organic growth projects since June 2010 and the increase of property, plant and equipment and intangible amounts resulting from the fair value adjustments upon the change of control resulting from the acquisition of our General Partner in May 2010.

Adjusted Total Segment Margin. Adjusted total segment margin increased to $99.2 million in the three months ended June 30, 2011 from $92.2 million in the combined three months ended June 30, 2010. The major components of this change were as follows:

Adjusted Gathering and Processing segment margin decreased to $52.6 million during the three months ended June 30, 2011 from $55.2 million for the combined three months ended June 30, 2010 primarily due to lower realized commodity prices and lower production in north Louisiana, offset by volume growth in the Eagle Ford Shale and west Texas. Total Gathering and Processing throughput increased to 1,063,000 MMBtu/d during the three months ended June 30, 2011 from 1,002,000 MMBtu/d during the three months ended June 30, 2010. Total NGL gross production increased to 28,000 Bbls/d during the three months ended June 30, 2011 from 25,000 Bbls/d during the three months ended June 30, 2010;

Contract Compression segment margin decreased to $37 million in the three months ended June 30, 2011 from $37.8 million in the combined three months ended June 30, 2010, which was primarily due to the decrease in intersegment transactions between the Gathering and Processing segment and the Contract Compression segment as a result of the transfer of certain compression units from the Contract Compression segment to the Gathering and Processing segment in the second quarter of 2011. The decrease was partially offset by an increase in revenue generating horsepower from external customers. As of June 30, 2011, our Contract Compression segment s total revenue generating horsepower was 758,000, compared to 727,000 as of June 30, 2010;

Contract Treating segment margin was $7.7 million for the three months ended June 30, 2011. We acquired the Contract Treating segment in September 2010. Revenue generating GPM as of June 30, 2011 was 3,368; and

Intersegment eliminations decreased to $2.9 million in the three months ended June 30, 2011 from $5.8 million in the three months ended June 30, 2010. The decrease was primarily due to a decrease in transactions between the Gathering and Processing and the Contract Compression segments as a result of the transfer of certain compression units from the Contract Compression segment to the Gathering and Processing segment in the second quarter of 2011.

Operation and Maintenance. Operation and maintenance expense increased to $34 million in the three months ended June 30, 2011 from $29.7 million during the combined three months ended June 30, 2010. The change was primarily due to the following:

$1.7 million increase in labor costs primarily due to higher short term incentives accrual; and

$1 million increase in consumable products primarily utilized in our Contract Compression segment.

General and Administrative. General and administrative expense decreased to $17.6 million in the three months ended June 30, 2011 from $28.9 million during the combined three months ended June 30, 2010. The change was primarily due to the following:

$9 million decrease in general and administrative expense related to the vesting of the outstanding restricted and phantom units that occurred in the second quarter of 2010 upon the change in control resulting from the acquisition of our General Partner;

$2.2 million decrease due to lower transaction costs primarily related to the acquisition of our General Partner by ETE, our acquisition of a 49.9% interest in MEP in May 2010 and our purchase of an additional 6.99% interest in HPC in April 2010; offset by

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$3.4 million increase in related party general and administrative expenses for the services agreements with Services Co. and ETC as described in footnote 8 to our financial statements.

Depreciation and Amortization. Depreciation and amortization expense increased to $40.5 million in the three months ended June 30, 2011 from $27.4 million in the combined three months ended June 30, 2010. This increase was the result of $6.8 million of additional depreciation and amortization expense due to the completion of various organic growth projects since June 2010 and $3.2 million related to our Contract Treating segment that we acquired in September 2010. In addition, we incurred $3.1 million of additional depreciation and amortization expense related to the increase of property, plant and equipment amounts resulting from the fair value adjustments upon the change of control resulting from the acquisition of our General Partner in May 2010. Had the change in control occurred on January 1, 2010, our depreciation and amortization expense for the three months ended June 30, 2010 would have been $30.5 million.

Income from Unconsolidated Affiliates. Income from unconsolidated affiliates increased to $32.2 million for the three months ended June 30, 2011 from $16.1 million for the combined three months ended June 30, 2010. The schedule summarizes the components of income from unconsolidated affiliates and our ownership interest for the three months ended June 30, 2011 and 2010, respectively:

	Three Months Ended June 30, 2011				Combined Three Months Ended June 30, 2010			
	HPC	**MEP**	**Lone Star**	**Total**	**HPC**	**MEP**	**Lone Star**	**Total**
Net income	$ 30,265	$ 20,276	$ 27,958	$ 78,499	$ 25,871	$ 8,068	N/A	$ 33,939
Average ownership interest	49.99%	49.9%	30%	N/M	48%	49.9%	N/A	N/M
Share of unconsolidated affiliates net income	15,130	10,110	8,388	33,628	12,419	4,026	N/A	16,445
Less: Amortization of excess fair value of unconsolidated affiliates	(1,461)			(1,461)	(365)		N/A	(365)
Income from unconsolidated affiliates	$ 13,669	$ 10,110	$ 8,388	$ 32,167	$ 12,054	$ 4,026	N/A	$ 16,080

N/A: Lone Star was purchased on May 2, 2011.

N/M: Not Meaningful

HPC s net income increased to $30.3 million for the three months ended June 30, 2011 from $25.9 million for the combined three months ended June 30, 2010, primarily due to increased throughput from 1,156,000 to 1,528,000 MMBtu/d.

We acquired our 49.9% interest in MEP in May 2010; therefore the net income in 2010 only reflected the period from May 26, 2010 to June 30, 2010.

The following table presents operational data for each of our unconsolidated affiliates for the three months ended June 30, 2011 and 2010:

		Three Months Ended June 30,	
	Operational data	**2011**	**2010**
HPC	Throughput (MMBtu/d)	1,528,333	1,155,692
MEP	Throughput (MMBtu/d)	1,197,520	1,595,120 (1) (3)
Lone Star	West Texas Pipeline Total Volumes (Bbls/d)	128,127 (2)	N/A
	Refinery Services Geismar Throughput (Bbls/d)	14,806 (2)	N/A

(1): 2010 throughput only represents the period from May 26, 2010 (initial acquisition date) to June 30, 2010.

(2): All Lone Star s operational volumes represent the period from May 2, 2011 (initial acquisition date) to June 30, 2011
(3): Despite the decrease in throughput, MEP s revenues remained relatively stable throughout the period because 100% of MEP s revenues are derived from firm transportation contracts with fixed fees.
N/A: Lone Star was purchased on May 2, 2011.

Other Income and Deductions, Net. Other income and deductions, net increased to a net gain of $2.6 million in the three months ended June 30, 2011 from a net loss of $4.1 million in the combined three months ended June 30, 2010, primarily due to the non-cash mark-to-market adjustment in the embedded derivatives related to the Series A Preferred Units.

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Six Months Ended June 30, 2011 vs. Combined Six Months Ended June 30, 2010

	Successor		Predecessor			
	Six Months Ended June 30, 2011	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from January 1, 2010 to May 25, 2010	Combined Six Months Ended June 30, 2010	Change	Percent
Total revenues	$ 673,750	$ 96,980	$ 505,050	$ 602,030	$ 71,720	12%
Cost of sales	475,736	70,174	357,778	427,952	(47,784)	11%
Total segment margin (1)	198,014	26,806	147,272	174,078	23,936	14%
Operation and maintenance	67,556	10,402	47,842	58,244	(9,312)	16%
General and administrative	36,660	7,104	37,212	44,316	7,656	17%
Loss on asset sales, net	181	10	303	313	132	42%
Depreciation and amortization	80,739	10,545	41,784	52,329	(28,410)	54%
Operating income (loss)	12,878	(1,255)	20,131	18,876	(5,998)	32%
Income from unconsolidated affiliates	55,975	8,121	15,872	23,993	31,982	133%
Interest expense, net	(44,696)	(8,081)	(34,541)	(42,622)	(2,074)	5%
Loss on debt refinancing, net			(1,780)	(1,780)	1,780	100%
Other income and deductions, net	5,055	(3,521)	(3,897)	(7,418)	12,473	168%
Income (loss) from continuing operations before income taxes	29,212	(4,736)	(4,215)	(8,951)	38,163	426%
Income tax expense	70	245	404	649	579	89%
Net income (loss) from continuing operations	29,142	(4,981)	(4,619)	(9,600)	38,742	404%
Discontinued operations		86	(327)	(241)	241	100%
Net income (loss)	29,142	(4,895)	(4,946)	(9,841)	38,983	396%
Net income attributable to noncontrolling interest	(524)	(29)	(406)	(435)	(89)	20%
Net income (loss) attributable to Regency Energy Partners LP	$ 28,618	$ (4,924)	$ (5,352)	$ (10,276)	$ 38,894	378%
Gathering and processing segment margin (2)	$ 104,295	$ 14,373	$ 85,997	$ 100,370	$ 3,925	4%
Non-cash loss from commodity derivatives	432	2,250	7,150	9,400	(8,968)	95%
Adjusted gathering and processing segment margin	104,727	16,623	93,147	109,770	(5,043)	5%
Contract compression segment margin (3)	78,413	12,488	62,356	74,844	3,569	5%
Contract treating segment margin	14,952				14,952	100%
Corporate and others segment margin (2)	9,815	1,943	8,045	9,988	(173)	2%
Intersegment eliminations (3)	(9,461)	(1,998)	(9,126)	(11,124)	1,663	15%
Adjusted total segment margin	$ 198,446	$ 29,056	$ 154,422	$ 183,478	$ 14,968	8%

(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 $9.5 million and $11.1 million for the six months ended June 30, 2011 and June 30, 2010, respectively. These intersegment revenues were eliminated upon consolidation.

Net Income (Loss) Attributable to Regency Energy Partners LP. Our net income increased to $28.6 million in the six months ended June 30, 2011 from a net loss of $10.3 million in the combined six months ended June 30, 2010. The major components of this change were as follows:

- $32 million increase in income from unconsolidated affiliates from the acquisition of a 30% interest in Lone Star in May 2011 and the acquisition of a 49.9% interest in MEP in May 2010;
- $23.9 million increase in total segment margin primarily from the addition of the Contract Treating segment acquired in September 2010;
- $12.5 million increase in other income and deductions, net which primarily relate to the non-cash value change associated with the embedded derivative related to the Series A Preferred Units;
- $7.7 million decrease in general and administrative expense primarily due to the absence of costs incurred from the change in control resulting from the acquisition of our General Partner in May 2010; offset by
- $28.4 million increase in depreciation and amortization expense primarily related to the completion of various organic growth projects since June 2010 and the increase of property, plant and equipment and intangible amounts resulting from the fair value adjustments upon the change of control resulting from the acquisition of our General Partner in May 2010; and
- $9.3 million increase in operation and maintenance expense primarily due to an increased short term compensation accrual as well as an increase in the utilization in consumable products.

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Adjusted Total Segment Margin. Adjusted total segment margin increased to $198.4 million in the six months ended June 30, 2011 from $183.5 million in the combined six months ended June 30, 2010. The major components of this increase were as follows:

- Adjusted Gathering and Processing segment margin decreased to $104.7 million during the six ended June 30, 2011 from $109.8 million for the combined six months ended June 30, 2010 primarily due to lower realized commodity prices. Total Gathering and Processing throughput increased to 1,034,000 MMBtu/d during the six months ended June 30, 2011 from 1,004,000 MMBtu/d during the six months ended June 30, 2010. Total NGL gross production increased to 28,000 Bbls/d during the six months ended June 30, 2011 from 24,000 Bbls/d during the six months ended June 30, 2010;

- Contract Compression segment margin increased to $78.4 million in the six months ended June 30, 2011 from $74.8 million in the combined six months ended June 30, 2010. The increase was primarily attributable to increased revenue generating horsepower provided to external customers. As of June 30, 2011, our Contract Compression segment s total revenue generating horsepower was 758,000 compared to 727,000 as of June 30, 2010;

- Contract Treating segment margin was $15 million for the six months ended June 30, 2011. We acquired the Contract Treating segment in September, 2010. Revenue generating GPM as of June 30, 2011 was 3,368; and

- Intersegment eliminations decreased to $9.5 million in the six months ended June 30, 2011 from $11.1 million in the six months ended June 30, 2010. The decrease was primarily due to a decrease in transactions between the Gathering and Processing and the Contract Compression segments as a result of the transfer of certain compression units from the Contract Compression segment to the Gathering and Processing segment in the second quarter of 2011.

Operation and Maintenance. Operation and maintenance expense increased to $67.6 million in the six months ended June 30, 2011 from $58.2 million during the combined six months ended June 30, 2010. The increase was primarily due to the following:

- $4.7 million increase in labor cost primarily due to an increased short term incentives accrual as well as an increase in the number of employees since June 30, 2010;

- $2.1 million increase in consumable products primarily utilized in our Contract Compression segment;

- $1.4 million increase in expense related to our Contract Treating segment that we acquired in September 2010; and

- $1.1 million increase in contractor expenses.

General and Administrative. General and administrative expense decreased to $36.7 million in the six months ended June 30, 2011 from $44.3 million during the combined six months ended June 30, 2010. The decrease was primarily due to the following:

- $9.5 million decrease in unit-based compensation related to the vesting of outstanding restricted and phantom units that occurred in May 2010 upon the change in control resulting from the acquisition of our General Partner;

- $1.8 million decrease in transaction costs primarily related to the acquisition of our General Partner by ETE, our acquisition of 49.9% interest in MEP and our purchase of an additional 6.99% interest in HPC;

- $2.7 million decrease in labor and labor related expenses primarily related to lower incentive compensation in our Contract Compression segment and a decrease in administrative employees; offset by

- $7.3 million increase in related party general and administrative expenses for the services agreements with Services Co. and ETC as described in footnote 8 to our financial statements.

Depreciation and Amortization. Depreciation and amortization expense increased to $80.7 million in the six months ended June 30, 2011 from $52.3 million in the combined six months ended June 30, 2010. This increase was the result of $14.8 million of additional depreciation and amortization expense due to the completion of various organic growth projects since June 2010 and $6 million related to our Contract Treating segment that we acquired in September 2010. In addition, $7.7 million 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 change in control resulting from the acquisition of our General Partner in May 2010. Had the change in control occurred on January 1, 2010, our depreciation and amortization expense for the combined six months ended June 30, 2010 would have been $60 million.

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Income from Unconsolidated Affiliates. Income from unconsolidated affiliates increased to $56.0 million for the six months ended June 30, 2011 from $24.0 million for the combined six months ended June 30, 2010. The schedule set forth below summarizes the components of income from unconsolidated affiliates and our ownership interest for the six months ended June 30, 2011 and 2010, respectively:

	Six Months Ended June 30, 2011				Combined Six Months Ended June 30, 2010			
	HPC	MEP	Lone Star	Total	HPC	MEP	Lone Star	Total
Net income	$ 60,421	$ 40,686	$ 27,958	$ 129,065	$ 44,274	$ 8,068	N/A	$ 52,342
Average ownership interest	49.99%	49.9%	30%	N/M	46%	49.9%	N/A	N/M
Share of unconsolidated affiliates net income	30,205	20,305	8,388	58,898	20,332	4,026	N/A	24,358
Less: Amortization of excess fair value of unconsolidated affiliates	(2,923)			(2,923)	(365)		N/A	(365)
Income from unconsolidated affiliates	$ 27,282	$ 20,305	$ 8,388	$ 55,975	$ 19,967	$ 4,026	N/A	$ 23,993

N/A: Lone Star was purchased on May 2, 2011.

N/M: Not Meaningful

HPC s net income increased to $60.4 million for the six months ended June 30, 2011 from $44.3 million for the combined six months ended June 30, 2010, primarily due to increased throughput from 1,020,000 MMBtu/d to 1,522,000 MMBtu/d.

We acquired our 49.9% interest in MEP in May 2010; therefore the net income in 2010 only reflected the period from May 26, 2010 to June 30, 2010.

The following table presents operational data for each of our unconsolidated affiliates for the six months ended June 30, 2011 and 2010:

		Six Months Ended June 30,	
	Operational data	2011	2010
HPC	Throughput (MMBtu/d)	1,522,515	1,019,913
MEP	Throughput (MMBtu/d)	1,208,614	1,595,120 (1) (3)
Lone Star	West Texas Pipeline Total Volumes (Bbls/d)	128,127 (2)	N/A
	Refinery Services Geismar Throughput (Bbls/d)	14,806 (2)	N/A

(1): 2010 throughput only represents the period from May 26, 2010 (initial acquisition date) to June 30, 2010.
(2): All Lone Star s operational volumes represent the period from May 2, 2011 (initial acquisition date) to June 30, 2011
(3): Despite the decrease in throughput, MEP s revenues remained relatively stable throughout the period because 100% of MEP s revenues are derived from firm transportation contracts with fixed fees.
N/A: Lone Star was purchased on May 2, 2011.

Other Income and Deductions, Net. Other income and deductions, net increased to a net gain of $5.1 million in the six months ended June 30, 2011 from a net loss of $7.4 million in the combined six months ended June 30, 2010, primarily due to the non-cash mark-to-market adjustment in the embedded derivatives related to the Series A Preferred Units.

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 change of control resulting from the acquisition of our General Partner in May 2010, together with the description of recently issued accounting standards.

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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. A 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. Until this matter is fully resolved, it is not known whether any amounts ultimately recorded 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 affiliates;
- debt offerings; and
- issuance of additional partnership units.

We expect our base growth capital expenditures to be $345 million in 2011, which includes $168 million for the Gathering and Processing segment, mostly in south Texas, $95 million for the Contract Compression segment, $65 million for the Joint Ventures segment, $12 million for the Contract Treating segment, and $5 million for the Corporate and Others segment. In addition, we expect our maintenance capital expenditures to be $17 million in 2011. We may revise the timing of these expenditures as necessary to adapt to economic conditions. We expect to fund our growth capital expenditures with borrowings under our revolving credit facility and a combination of debt and equity issuances.

We do not anticipate contributing any amounts to HPC in 2011 to fund their growth capital expenditures as these amounts are expected to be funded under their 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 we permanently financed them. 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 revenues as a current liability, which represents billings in advance of services performed. As the revenues associated with the deferred revenues are earned, the liability is reduced.

Our working capital deficit increased to $55 million at June 30, 2011 from $35.1 million at December 31, 2010. This increase was primarily due to a $31.6 million decrease from the net changes in related party payables and receivables, primarily resulting from transactions with affiliates of ETE. This decrease primarily was offset by a $14.7 million increase in trade receivables and payables due to the timing of cash receipts and disbursements.

Cash Flows from Operating Activities. Net cash flows provided by operating activities increased to $121.1 million in the six months ended June 30, 2011 from $73.2 million in the combined six months ended June 30, 2010. The increase in cash flows from operating activities was primarily due to an increase in segment margin and additional distributions from unconsolidated affiliates primarily due to the acquisition of interests in MEP in May 2010.

Cash Flows used in Investing Activities. Net cash flows used in investing activities increased to $731.9 million in the six months ended June 30, 2011 from $195.4 million in the combined six months ended June 30, 2010, primarily related to capital expenditures for growth projects and the May 2011 acquisition of interest in Lone Star.

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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 six months ended June 30, 2011, we incurred $123.7 million of growth capital expenditures. Growth capital expenditures for the six months ended June 30, 2011, primarily related to $45.1 million for the fabrication of new compressor packages for our Contract Compression segment, $73.2 million for organic growth projects for our Gathering and Processing segment and $5.4 million 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 six months ended June 30, 2011, we incurred $5.4 million of maintenance capital expenditures.

Cash Flows from Financing Activities. Net cash flows provided by financing activities increased to $604.5 million in the six months ended June 30, 2011 from $116.6 million during the same period in 2010. The increase is primarily due to a $500 million senior note offering and an equity issuance resulting in net proceeds of $203.9 million in May 2011. These cash flows were partially offset by increased Partnership distributions.

Capital Resources. In May 2011, we issued 8,500,001 common units representing limited partnership interests resulting in net proceeds of $203.9 million, to partially fund our capital contribution to Lone Star. These units were issued in a private placement conducted in accordance with the exemption from the registration requirements of the Securities Act of 1933, as amended, under section 4(2) thereof. These units were subsequently registered with the SEC.

Amendment of Revolving Credit Facility. In May 2011, we amended our Fifth Amended and Restated Credit Agreement to permit the acquisition of equity interest in Lone Star and to allow for additional investments in Lone Star of up to $150 million.

Senior Notes Offering. During the second quarter of 2011, we issued $500 million in senior notes that mature on July 15, 2021. The senior notes bear interest at 6.5% payable semi-annually in arrears on January 15 and July 15, commencing January 15, 2012. The proceeds were used to repay borrowings outstanding under our revolving credit facility.

Cash Distributions from Unconsolidated Affiliates. During the six months ended June 30, 2011, we received cash distributions of $43.7 million and $34.8 million 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.

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The following table sets forth certain information regarding our hedges for natural gas, NGLs, and WTI, outstanding at June 30, 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)	Effect of Hypothetical Change in Index*
					(in thousands)	
July 2011-September 2012	Ethane	599 (MBbls)	Index	$ 0.48($/gallon)	$ (4,933)	$ 1,700
July 2011-March 2013	Propane	442 (MBbls)	Index	1.09($/gallon)	(6,157)	2,641
July 2011-March 2013	Normal Butane	265 (MBbls)	Index	1.47($/gallon)	(2,940)	1,935
July 2011-March 2013	Natural Gasoline	142 (MBbls)	Index	1.91($/gallon)	(2,611)	1,398
July 2011-March 2014	West Texas Intermediate Crude	483 (MBbls)	Index	91.84($/Bbl)	(3,651)	4,789
July 2011-December 2012	Natural gas	3,670,000 (MMBtu)	Index	5.07($/MMBtu)	1,371	1,724
July 2011-April 2012	Interest Rate	$ 250,000,000	1.325%	Three-month LIBOR	(1,852)	2,459
				Total Fair Value	$ (20,773)	

* Price risk sensitivities were calculated by assuming a theoretical 10% 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 General Partner, concluded that our disclosure controls and procedures were effective as of June 30, 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 began integrating certain business functions under a shared services agreement with Services Co. In connection with this integration, certain controls and procedures have been changed to conform to the existing controls of the shared services provider. During the three months ended June 30, 2011, the Partnership s accounting systems were transitioned to the accounting systems of the shared services provider and accordingly certain related controls changed at that time. None of these changes are in response to any identified deficiency or weakness in our internal controls over financial reporting.

There were no other changes in our internal controls over financial reporting (as defined in Rule 13(a) 15(f) or Rule 15d 15(f) of the Exchange Act) during the three months ended June 30, 2011 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

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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

For information regarding risk, uncertainties and assumptions, see Part I, Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2010. Except as disclosed below, there are no material changes from the risk factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2010 and our Quarterly Report on Form 10-Q for the quarter ended March 31, 2011.

RISKS RELATED TO OUR BUSINESS

We may have difficulty financing our planned capital expenditures, including in our joint ventures, which could adversely affect our results and growth.

We expect that we will distribute all of our available cash to our unitholders and will rely primarily upon external financing sources, including borrowings under our revolving credit facility and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. If we are not able to obtain adequate financing from the capital markets, our ability to grow and our results of operations could be adversely impacted. To access amounts under our credit facility for joint venture capital expenditures or additional investments, we may need to seek an amendment to our credit facility, and we cannot assure you that we can obtain any such amendment.

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

None.

Item 3. Defaults upon Senior Securities

None.

Item 4.

[Removed and Reserved]

Item 5. Other Information

None.

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Item 6. Exhibits

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

Exhibit 4.4	Second Supplemental Indenture dated May 24, 2011 among the Guaranteeing Subsidiaries, Regency Energy Partners LP, Regency Energy Finance Corp. and Wells Fargo Bank, National Association, as trustee. (Incorporated by reference to Exhibit 4.4 to our current report on Form 8-K filed May 26, 2010.)
Exhibit 4.7	Second Supplemental Indenture dated May 24, 2011 among Regency Energy Partners LP, Regency Energy Finance Corp., the guarantors party thereto and U.S. Bank National Association, as trustee. (Incorporated by reference to Exhibit 4.2 to our current report on Form 8-K dated May 26, 2011.)
Exhibit 4.8	Third Supplemental Indenture dated May 26, 2011 among the Guaranteeing Subsidiaries, Regency Energy Partners LP, Regency Energy Finance Corp. and U.S. Bank National Association, as trustee. (Incorporated by reference to Exhibit 4.3 to our current report on Form 8-K dated May 26, 2011.)
Exhibit 4.12	Registration Rights Agreement dated May 2, 2011 by and between Regency Energy Partners LP and the purchasers set forth on Schedule I thereto. (Incorporated by reference to Exhibit 4.1 to our current report on Form 8-K filed May 2, 2011.)
Exhibit 10.3	Operation and Service Agreement by and between La Grange Acquisition, L.P., Regency GP LP, Regency Energy Partners LP and Regency Gas Services LP, dated May 19, 2011. (Incorporated by reference to Exhibit 10.1 to our Form 8-K dated May 19, 2011.)
Exhibit 16.1	Letter from KPMG LLP to the Securities and Exchange Commission, dated April 4, 2011. (Incorporated by reference to Exhibit 16.1 to our Form 8-K/A dated April 4, 2011.)
Exhibit 23.1	Consent of the Independent Auditors (Incorporated by reference to Exhibit 23.1 to our Form 8-K dated May 20, 2011.)
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 99.1 -	Statement of Policies Related to Potential Conflicts Among Energy Transfer Partners, L.P., Energy Transfer Equity, L.P. and Regency Energy Partners LP, dated as of April 26, 2011.
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

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SIGNATURE

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

REGENCY ENERGY PARTNERS LP

By: Regency GP LP, its general partner

By: Regency GP LLC, its general partner

Date: August 8, 2011

/s/ A. TROY STURROCK
A. Troy Sturrock

Vice President, Controller and Principal Accounting Officer

(Duly Authorized Officer)