Regency Energy Partners LP
Form 10-Q
November 08, 2012
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
(Mark One)

ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2012
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: 001-35262
REGENCY ENERGY PARTNERS LP
(Exact name of registrant as specified in its charter)

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

(214) 750-1771
(Registrant's telephone number, including area code)

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 ý 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 ý 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	ý	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 ý

The issuer had 170,804,695 common units outstanding as of November 1, 2012.

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Introductory Statement

References in this report to the “Partnership,” “we,” “our,” “us” and similar terms refer to Regency Energy Partners LP 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 (Loss)
Bbls	Barrels
BTU	A unit of energy needed to raise the temperature of one pound of water by one degree Fahrenheit
Citi	Citigroup Global Markets Inc.
Edwards Lime	Edwards Lime Gathering, LLC, ELG Oil LLC and ELG Utility LLC which are 60% owned by the Partnership
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.
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
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
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
Lone Star	Lone Star NGL LLC, which is 30% owned by the Partnership and 70% owned by ETP
LTIP	Long-Term Incentive Plan
MEP	Midcontinent Express Pipeline LLC, which is 50% owned by the Partnership
MBbls	One thousand barrels
MMBtu	One million BTUs
MMcf	One million cubic feet
NGLs	Natural gas liquids, including ethane, propane, normal butane, iso butane and natural gasoline
NYMEX	New York Mercantile Exchange
Partnership	Regency Energy Partners LP and its subsidiaries
Ranch JV	Ranch Westex JV LLC, which is 33.33% owned by the Partnership
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, a wholly owned subsidiary of ETE
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-looking statements. Although we believe our forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, we cannot give assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions including without limitation the following:

- volatility in the price of oil, natural gas, and NGLs;
- 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 and safety;
- weather and other natural phenomena;
- industry changes including the impact of consolidations and changes in competition;
- regulation of transportation rates on our natural gas and NGL pipelines;
- our ability to obtain indemnification related to 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, 2011 Annual Report on Form 10-K and our Quarterly Report on Form 10-Q for the quarter ended March 31, 2012.

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

	September 30, 2012	December 31, 2011
ASSETS		
Current Assets:		
Cash and cash equivalents	$36,464	$990
Trade accounts receivable, net of allowance of $954 and $1,190	32,289	43,917
Accrued revenues	87,778	68,011
Related party receivables	19,138	45,204
Derivative assets	7,787	4,374
Other current assets	26,228	24,628
Total current assets	209,684	187,124
Property, plant and equipment:		
Property, plant and equipment	2,367,865	2,080,932
Less accumulated depreciation	(308,669)	(195,404)
Property, plant and equipment, net	2,059,196	1,885,528
Other Assets:		
Investment in unconsolidated affiliates	2,156,135	1,924,705
Long-term derivative assets	918	474
Other, net of accumulated amortization of debt issuance costs of $15,175 and $10,186	33,486	39,353
Total other assets	2,190,539	1,964,532
Intangible assets, net of accumulated amortization of $66,811 and $44,856	718,928	740,883
Goodwill	789,789	789,789
TOTAL ASSETS	$5,968,136	$5,567,856
LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST		
Current Liabilities:		
Drafts payable	$—	$2,507
Trade accounts payable	67,976	73,462
Accrued cost of gas and liquids	66,220	84,943
Related party payables	23,791	12,625
Deferred revenues, including related party amounts of $71 and $41	15,149	16,225
Derivative liabilities	803	10,535
Other current liabilities	40,168	33,009
Total current liabilities	214,107	233,306
Long-term derivative liabilities	29,490	39,112
Other long-term liabilities	5,550	6,071
Long-term debt, net	1,960,429	1,687,147
Commitments and contingencies		
Series A Preferred Units, redemption amount of $85,129 and $84,773	72,549	71,144
Partners' capital and noncontrolling interest:		
Common units	3,299,389	3,173,090
General partner interest	327,160	329,876
Accumulated other comprehensive income (loss)	1,330	(4,759)
Total partners' capital	3,627,879	3,498,207

Noncontrolling interest	58,132	32,869
Total partners’ capital and noncontrolling interest	3,686,011	3,531,076
TOTAL LIABILITIES AND PARTNERS’ CAPITAL AND NONCONTROLLING INTEREST	$5,968,136	$5,567,856

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)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
REVENUES				
Gas sales, including related party amounts of $4,507, $3,840, $13,788 and $15,479	$82,437	$118,754	$227,374	$361,641
NGL sales, including related party amounts of $(773), $103,892, $22,195 and $253,933	124,651	174,537	404,914	430,876
Gathering, transportation and other fees, including related party amounts of $9,024, $6,141, $23,024 and $17,611	101,410	91,596	296,989	255,249
Net realized and unrealized (loss) gain from derivatives	(5,232)	(5,380)	8,571	(14,636)
Other, including related party amounts of $1, $2,665, $1,479 and $7,455	10,616	10,760	45,909	30,887
Total revenues	313,882	390,267	983,757	1,064,017
OPERATING COSTS AND EXPENSES				
Cost of sales, including related party amounts of $4,391, $5,049, $12,965 and $16,070	206,881	279,526	633,349	755,262
Operation and maintenance	41,275	37,950	121,248	105,506
General and administrative, including related party amounts of $4,300, $4,225, $12,900 and $12,354	14,935	17,350	47,106	54,010
(Gain) loss on asset sales, net	(42)	(131)	1,542	50
Depreciation and amortization	45,881	41,956	142,519	122,695
Total operating costs and expenses	308,930	376,651	945,764	1,037,523
OPERATING INCOME	4,952	13,616	37,993	26,494
Income from unconsolidated affiliates	21,055	30,946	87,198	86,921
Interest expense, net	(28,567)	(28,852)	(86,058)	(73,548)
Loss on debt refinancing, net	—	—	(7,820)	—
Other income and deductions, net	1,106	15,050	25,549	20,105
(LOSS) INCOME BEFORE INCOME TAXES	(1,454)	30,760	56,862	59,972
Income tax expense (benefit)	—	(89)	89	(19)
NET (LOSS) INCOME	(1,454)	30,849	56,773	59,991
Net loss attributable to noncontrolling interest	(379)	(549)	(1,427)	(1,073)
NET (LOSS) INCOME ATTRIBUTABLE TO REGENCY ENERGY PARTNERS LP	$(1,833)	$30,300	$55,346	$58,918
Amounts attributable to Series A Preferred Units	2,125	1,997	7,242	5,985
General partner’s interest, including IDRs	2,019	2,060	7,012	4,902
Limited partners’ interest in net (loss) income	$(5,977)	$26,243	$41,092	$48,031
Basic and diluted net income per common unit:				
Weighted average number of common units outstanding	170,264,621	145,842,735	166,368,178	142,058,631
Basic (loss) income per common unit	$(0.04)	$0.18	$0.25	$0.34
Diluted (loss) income per common unit	$(0.04)	$0.09	$0.22	$0.23
Distributions per common unit	$0.46	$0.455	$1.38	$1.35

See accompanying notes to condensed consolidated financial statements

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Net (loss) income	$(1,454)	$30,849	$56,773	$59,991
Other comprehensive income (loss):				
Net cash flow hedge amounts reclassified to earnings	265	5,282	6,089	14,276
Change in fair value of cash flow hedges	—	10,287	—	(5,179)
Total other comprehensive income	265	15,569	6,089	9,097
Comprehensive (loss) income	(1,189)	46,418	62,862	69,088
Comprehensive income attributable to noncontrolling interest	379	549	1,427	1,073
Comprehensive (loss) income attributable to Regency Energy Partners LP	$(1,568)	$45,869	$61,435	$68,015

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)

	Nine Months Ended September 30,	
	2012	2011
OPERATING ACTIVITIES:		
Net income	$56,773	$59,991
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization, including debt issuance cost and bond premium amortization	146,913	127,079
Income from unconsolidated affiliates	(87,198)	(86,921)
Derivative valuation changes	(17,124)	(21,660)
Loss on asset sales, net	1,542	50
Unit-based compensation expenses	3,470	2,444
Cash flow changes in current assets and liabilities:		
Trade accounts receivable, accrued revenues and related party receivables	10,779	(13,298)
Other current assets	(1,429)	186
Trade accounts payable, accrued cost of gas and liquids, related party payables and deferred revenues	(31,675)	20,467
Other current liabilities	7,159	24,833
Distributions received from unconsolidated affiliates	91,893	91,306
Other assets and liabilities	(178)	(61)
Net cash flows provided by operating activities	180,925	204,416
INVESTING ACTIVITIES:		
Capital expenditures	(306,159)	(290,889)
Capital contributions to unconsolidated affiliates	(272,759)	(23,646)
Acquisitions of investments in unconsolidated affiliates, net of cash received	—	(593,843)
Distributions in excess of earnings of unconsolidated affiliates	49,814	40,354
Proceeds from asset sales	22,004	10,232
Net cash flows used in investing activities	(507,100)	(857,792)
FINANCING ACTIVITIES:		
Net borrowings under revolving credit facility	363,000	160,000
Proceeds from issuance of senior notes	—	500,000
Redemption of senior notes	(87,500)	—
Debt issuance costs	(1,438)	(9,955)
Drafts payable	(2,507)	—
Partner distributions	(240,304)	(199,640)
Transfer of assets between entities under common control in excess of historical cost	436	66
Contributions from noncontrolling interest	23,836	—
Issuance of common units under LTIP, net of forfeitures and tax withholding	(207)	655
Common unit offering, net of costs	296,817	203,917
Common units issued under equity distribution program, net of costs	15,352	—
Distributions to Series A Preferred Units	(5,836)	(5,836)
Net cash flows provided by financing activities	361,649	649,207
Net change in cash and cash equivalents	35,474	(4,169)
Cash and cash equivalents at beginning of period	990	9,400

Cash and cash equivalents at end of period	$36,464	$5,231
Supplemental Cash Flow Information:		
Accrued capital expenditures and contributions to unconsolidated affiliates	$41,668	$25,504
Deemed contribution from acquisition of assets between entities under common control	—	177

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
(in thousands except unit data)
(unaudited)

	Regency Energy Partners LP Units					
	Common	Common Unitholders	General Partner Interest	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interest	Total
Balance - December 31, 2011	157,437,608	$3,173,090	$329,876	$ (4,759)	$ 32,869	$3,531,076
Common unit offering, net of costs	12,650,000	296,817	—	—	—	296,817
Common units issued under equity distribution program, net of costs	691,129	15,352	—	—	—	15,352
Issuance of common units under LTIP, net of forfeitures and tax withholding	25,958	(207)	—	—	—	(207)
Unit-based compensation expenses	—	3,470	—	—	—	3,470
Transfer of assets between entities under common control in excess of historical cost	—	—	436	—	—	436
Partner distributions	—	(230,262)	(10,042)	—	—	(240,304)
Accrued distributions to phantom units	—	(86)	—	—	—	(86)
Net income	—	48,334	7,012	—	1,427	56,773
Contributions from noncontrolling interest	—	—	—	—	23,836	23,836
Distributions to Series A Preferred Units	—	(5,738)	(98)	—		(5,836)
Accretion of Series A Preferred Units	—	(1,381)	(24)	—	—	(1,405)
Net cash flow hedge amounts reclassified to earnings	—	—	—	6,089	—	6,089
Balance - September 30, 2012	170,804,695	$3,299,389	$327,160	$ 1,330	$ 58,132	$3,686,011

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 ("Partnership"), a Delaware limited partnership. The Partnership is engaged in the business of gathering and processing, contract compression, treating and transportation of natural gas and the transportation, fractionation and storage of NGLs. Regency GP LP is the Partnership's general partner and Regency GP LLC (collectively the "General Partner") is the general partner of Regency GP LP.

Basis of Presentation. 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, 2011. In the opinion of the Partnership's management, such financial information reflects all adjustments necessary for a fair presentation of the financial position and the results of operations for such interim periods in accordance with GAAP. All intercompany items and transactions have been eliminated in consolidation. Certain information and footnote disclosures normally included in annual consolidated financial statements prepared in accordance with GAAP have been omitted pursuant to the rules and regulations of the SEC.

Use of Estimates. The unaudited condensed consolidated financial statements have been prepared in conformity with GAAP, 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.

Property, Plant and Equipment. In March 2012, the Partnership recorded a $6.9 million "out-of-period" adjustment to depreciation expense to correct the estimated useful lives of certain assets to comply with its policy. The adjustment to depreciation expense related to the year ended December 31, 2011 and the period from May 26, 2010 to December 31, 2010 was $4.4 million and $2.5 million, respectively. The adjustment to depreciation expense related to the three and nine months ended September 30, 2011 was $1.1 million and $3.3 million, respectively.

2. Partners' Capital and Distributions

Equity Distribution Agreement. On June 19, 2012, the Partnership entered into an Equity Distribution Agreement with Citi under which the Partnership may offer and sell common units, representing limited partner interests, having an aggregate offering price of up to $200 million, from time to time through Citi, as sales agent for the Partnership. Sales of these units, if any, made from time to time under the Equity Distribution Agreement will be made by means of ordinary brokers' transactions on the New York Stock Exchange at market prices, in block transactions, or as otherwise agreed upon by the Partnership and Citi. The Partnership may also sell common units to Citi as principal for its own account at a price agreed upon at the time of sale. Any sale of common units to Citi as principal would be pursuant to the terms of a separate agreement between the Partnership and Citi. The Partnership intends to use the net proceeds from the sale of these units for general partnership purposes. As of September 30, 2012, the Partnership has issued 691,129 common units resulting in net proceeds of $15.4 million.

Quarterly Distributions of Available Cash. Following are distributions declared by the Partnership subsequent to December 31, 2011:

Quarter Ended	Record Date	Payment Date	Cash Distributions (per common unit)
December 31, 2011	February 6, 2012	February 13, 2012	$0.46
March 31, 2012	May 7, 2012	May 14, 2012	$0.46
June 30, 2012	August 6, 2012	August 14, 2012	$0.46
September 30, 2012	November 6, 2012	November 14, 2012	$0.46

Common Unit Offering. In March 2012, the Partnership issued 12,650,000 common units representing limited partner interests in a public offering at a price of $24.47 per common unit, resulting in net proceeds of $296.8 million. In May 2012, the Partnership used the net proceeds from this offering to redeem 35%, or $87.5 million, in aggregate principal amounts of its outstanding senior notes due 2016; pay related premium, expenses and accrued interest; and repay outstanding borrowings under the revolving credit facility.

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3. (Loss) Income per Common Unit

The following tables provide a reconciliation of the numerator and denominator of the basic and diluted earnings per common unit computations for the three and nine months ended September 30, 2012 and 2011:

	Three Months Ended September 30,					
	2012			2011		
	(Loss) (Numerator)	Units (Denominator)	Per-Unit Amount	Income (Numerator)	Units (Denominator)	Per-Unit Amount
Basic (loss) income per unit						
Limited Partners' interest in net (loss) income	$(5,977)	170,264,621	$(0.04)	$26,243	145,842,735	$0.18
Effect of Dilutive Securities:						
Common unit options	—	—		—	13,633	
Phantom units *	—	—		—	281,320	
Series A Preferred Units	—	—		(13,233)	4,626,197	
Diluted (loss) income per unit	$(5,977)	170,264,621	$(0.04)	$13,010	150,763,885	$0.09

	Nine Months Ended September 30,					
	2012			2011		
	Income (Numerator)	Units (Denominator)	Per-Unit Amount	Income (Numerator)	Units (Denominator)	Per-Unit Amount
Basic income per unit						
Limited Partners' interest in net income	$41,092	166,368,178	$0.25	$48,031	142,058,631	$0.34
Effect of Dilutive Securities:						
Common unit options	—	13,113		—	23,450	
Phantom units *	—	320,452		—	237,192	
Series A Preferred Units	(2,713)	4,651,884		(14,770)	4,626,197	
Diluted income per unit	$38,379	171,353,627	$0.22	$33,261	146,945,470	$0.23

* 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:

	Three Months Ended September 30, 2012
Common unit options	9,147
Phantom units *	313,378
Series A Preferred Units	4,651,884

* Amount assumes maximum conversion rate for market condition awards.

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4. Investment in Unconsolidated Affiliates

As of September 30, 2012, the Partnership has a 49.99% general partner interest in HPC, a 50% membership interest in MEP, a 30% membership interest in Lone Star, and a 33.33% membership interest in Ranch JV. The carrying value of the Partnership's investment in each of the unconsolidated affiliates as of September 30, 2012 and December 31, 2011 is as follows:

	September 30, 2012	December 31, 2011
HPC	$658,869	$682,046
MEP	588,800	613,942
Lone Star	876,133	628,717
Ranch JV	32,333	—
	$2,156,135	$1,924,705

The following tables summarize the Partnership's investment activities in each of the unconsolidated affiliates for the three and nine months ended September 30, 2012 and 2011:

	Three Months Ended September 30, 2012			
	HPC	MEP	Lone Star	Ranch JV
Contributions to unconsolidated affiliates	$—	$—	$78,042	$10,287
Distributions from unconsolidated affiliates	16,438	18,263	21,051	—
Share of unconsolidated affiliates' net income (loss)	3,259	10,367	9,184	(293)
Amortization of excess fair value of investment	(1,462)	—	—	—

	Three Months Ended September 30, 2011			
	HPC	MEP	Lone Star(1)	Ranch JV
Contributions to unconsolidated affiliates	$—	$—	$24,630	N/A
Distributions from unconsolidated affiliates	15,022	19,238	18,900	N/A
Share of unconsolidated affiliates' net income	12,138	10,985	9,285	N/A
Amortization of excess fair value of investment	(1,462)	—	—	N/A

	Nine Months Ended September 30, 2012			
	HPC	MEP	Lone Star	Ranch JV
Contributions to unconsolidated affiliates	$—	$—	$253,296	$32,643
Distributions from unconsolidated affiliates	46,468	56,445	38,794	—
Share of unconsolidated affiliates' net income (loss)	27,676	31,303	32,914	(310)
Amortization of excess fair value of investment	(4,385)	—	—	—

	Nine Months Ended September 30, 2011			
	HPC	MEP	Lone Star(1)	Ranch JV
Contributions to unconsolidated affiliates	$—	$—	$616,311	N/A
Distributions from unconsolidated affiliates	49,863	62,897	18,900	N/A
Share of unconsolidated affiliates' net income	42,343	31,290	17,673	N/A
Amortization of excess fair value of investment	(4,385)	—	—	N/A

(1) For the period from initial contribution, May 2, 2011, to September 30, 2011.

N/A The Partnership acquired a 33.33% membership interest in Ranch JV in December 2011.

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The following tables present selected income statement data for each of the unconsolidated affiliates, on a 100% basis, for the three and nine months ended September 30, 2012 and 2011:

	Three Months Ended September 30, 2012			
	HPC	MEP	Lone Star	Ranch JV
Total revenues	$42,212	$65,052	$164,931	$20
Operating income (loss)	21,088	33,547	31,128	(880)
Net income (loss)	6,520	20,735	30,611	(880)
	Three Months Ended September 30, 2011			
	HPC	MEP	Lone Star(1)	Ranch JV
Total revenues	$43,809	$65,853	$146,596	N/A
Operating income	24,627	34,852	30,936	N/A
Net income	24,282	21,998	30,952	N/A
	Nine Months Ended September 30, 2012			
	HPC	MEP	Lone Star	Ranch JV
Total revenues	$130,352	$196,181	$489,517	$150
Operating income (loss)	70,737	101,210	109,748	(931)
Net income (loss)	55,364	62,606	109,712	(931)
	Nine Months Ended September 30, 2011			
	HPC	MEP	Lone Star(1)	Ranch JV
Total revenues	$141,043	$195,620	$245,416	N/A
Operating income	85,469	101,307	59,079	N/A
Net income	84,703	62,684	58,910	N/A

(1) For the period from initial contribution, May 2, 2011, to September 30, 2011.
N/A The Partnership acquired a 33.33% membership interest in Ranch JV in December 2011.

5. Derivative Instruments

Policies. The Partnership established comprehensive risk management policies and procedures to monitor and manage the market risks associated with commodity prices, counterparty credit and interest rates. The General Partner is responsible for delegation of transaction authority levels, and the Audit and Risk Committee of the General Partner is responsible for the oversight of these risks, including monitoring exposure limits. The Audit and Risk 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 market forces. Both the Partnership's profitability and cash flow are affected by the inherent volatility of these commodities which could adversely affect its ability to make distributions to its unitholders. The Partnership manages this commodity price exposure through an integrated strategy that includes management of its contract portfolio, matching sales prices of commodities with purchases, optimization of its portfolio by monitoring basis and other price differentials in operating areas, and the use of derivative contracts. In some cases, the Partnership may not be able to match pricing terms or cover its risk to price exposure with financial hedges, and it may be exposed to commodity price risk. Speculative positions with derivative contracts are prohibited under the Partnership's policies.

The Partnership has swap contracts settled against NGLs (ethane, propane, butane, and natural gasoline), condensate and natural gas market prices. The Partnership also has put options to protect against falling ethane prices.

On January 1, 2012, the Partnership de-designated its swap contracts and began accounting for these contracts using the mark-to-market method of accounting. As of September 30, 2012, the Partnership has $1.3 million in net hedging gains in AOCI which will be amortized to earnings over the next 1.5 years, $1.2 million of which will be over the next 12 months.

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Interest Rate Risk. The Partnership is exposed to variable interest rate risk as a result of borrowings under its revolving credit facility. The Partnership's $250 million interest rate swaps expired in April 2012.

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.

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 September 30, 2012 would be $7.5 million. 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.

The Partnership’s derivative assets and liabilities, including credit risk adjustments, as of September 30, 2012 and December 31, 2011 are detailed below:

	Assets		Liabilities	
	September 30, 2012	December 31, 2011	September 30, 2012	December 31, 2011
Derivatives designated as cash flow hedges:				
Current amounts				
Commodity contracts	$—	$4,065	$—	$10,065
Long-term amounts				
Commodity contracts	—	474	—	63
Total cash flow hedging instruments	—	4,539	—	10,128
Derivatives not designated as cash flow hedges:				
Current amounts				
Commodity contracts	6,757	—	803	—
Ethane put options	1,030	309	—	—
Interest rate swap contracts	—	—	—	470
Long-term amounts				
Commodity contracts	918	—	396	—
Embedded derivatives in Series A Preferred Units	—	—	29,094	39,049
Total derivatives not designated as cash flow hedges	8,705	309	30,293	39,519
Total derivatives	$8,705	$4,848	$30,293	$49,647

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The Partnership's statements of operations and comprehensive (loss) income for the three and nine months ended September 30, 2012 and 2011 were impacted by derivative instruments activities as follows:

		Three Months Ended September 30,	
		2012	2011
Derivatives in cash flow hedging relationships:		Change in Value Recognized in AOCI on Derivatives (Effective Portion)	
Commodity derivatives		$—	$10,287
Derivatives in cash flow hedging relationships:	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	
Commodity derivatives	Revenues	$—	$(5,282)
Derivatives in cash flow hedging relationships:	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) Recognized in Income on Ineffective Portion	
Commodity derivatives	Revenues	$—	$21
Derivatives not designated in a hedging relationship:	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) from De-designation Amortized from AOCI into Income	
Commodity derivatives	Revenues	$(265)	$—
Derivatives not designated in a hedging relationship:	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) Recognized in Income on Derivatives	
Commodity derivatives	Revenues	$(4,967)	$(119)
Interest rate swap contracts	Interest expense, net	—	99
Embedded derivatives in Series A Preferred Units	Other income & deductions, net	1,550	15,230
		$(3,417)	$15,210

		Nine Months Ended September 30,	
		2012	2011
Derivatives in cash flow hedging relationships:		Change in Value Recognized in AOCI on Derivatives (Effective Portion)	
Commodity derivatives		$—	$(5,179)
Derivatives in cash flow hedging relationships:	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	
Commodity derivatives	Revenues	$—	$(14,276)
Derivatives in cash flow hedging relationships:	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) Recognized in Income on Ineffective Portion	
Commodity derivatives	Revenues	$—	$(253)
Derivatives not designated in a hedging relationship:	Location of Gain/(Loss)		

	Recognized in Income	Amount of Gain/(Loss) from De-designation Amortized from AOCI into Income	
Commodity derivatives	Revenues	$(6,089)	$—

Derivatives not designated in a hedging relationship:	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) Recognized in Income on Derivatives	
Commodity derivatives	Revenues	$14,660	$(107)
Interest rate swap contracts	Interest expense, net	(12)	(388)
Embedded derivatives in Series A Preferred Units	Other income & deductions, net	9,955	20,755
		$24,603	$20,260

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6. Long-term Debt

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

	September 30, 2012	December 31, 2011
Senior notes	$1,265,429	$1,355,147
Revolving loans	695,000	332,000
Total	1,960,429	1,687,147
Less: current portion	—	—
Long-term debt	$1,960,429	$1,687,147
Availability under revolving credit facility:		
Total credit facility limit	$1,150,000	$900,000
Revolving loans	(695,000)	(332,000)
Letters of credit	(8,600)	(19,000)
Total available	$446,400	$549,000

Scheduled maturities of long-term debt at September 30, 2012 are as follows:

Years Ending December 31,	Amount
2012 (remainder)	$—
2013	—
2014	695,000
2015	—
2016	162,500
Thereafter	1,100,000
Total	$1,957,500 *

*Excludes unamortized premiums of $2.9 million as of September 30, 2012.

Revolving Credit Facility. In August 2012, RGS exercised the accordion feature of the Fifth Amended and Restated Credit Agreement (the "Credit Agreement") to increase its commitments under the revolving credit facility by $250 million to a total of $1.15 billion. The new commitments will be available pursuant to the same terms and subject to the same interest rates and fees as the existing commitments under the Credit Agreement. The weighted average interest rate on the total amounts outstanding under the Partnership's revolving credit facility was 2.72% and 3.03% as of September 30, 2012 and 2011, respectively.

Senior Notes. In October 2012, the Partnership and Finance Corp. issued $700 million in senior notes that mature on April 15, 2023 (the “2023 Notes”). The 2023 Notes bear interest at 5.5% payable semi-annually in arrears on April 15 and October 15, commencing April 15, 2013. The proceeds were used to repay borrowings outstanding under the Partnership’s revolving credit facility.

At any time prior to October 15, 2015, the Partnership may redeem up to 35% of the 2023 Notes at a price equal to 105.5% plus accrued interest. Beginning on October 15 of the years indicated below, the Partnership may redeem all or part of the 2023 Notes at the redemption prices, expressed as percentages of the principal amount, set forth below:

October 15 of year ending:	Percentage of Redemption Price
2017	102.750%
2018	101.833%
2019	100.917%
2020 and thereafter	100.000%

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Upon a change of control, as defined in the indenture, followed by a rating decline within 90 days, each holder of the 2023 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 its debt agreements, including the Partnership's revolving credit facility.

The 2023 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

In May 2012, the Partnership exercised its option to redeem 35% or $87.5 million of its outstanding senior notes due 2016 at a price of 109.375% of the principal amount plus accrued interest.

At September 30, 2012, the Partnership was in compliance with all debt covenants.

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. The senior notes due in years 2016, 2018, 2021 and 2023 are fully and unconditionally and jointly and severally guaranteed by all of the Partnership’s current consolidated subsidiaries, other than Finance Corp. and several minor subsidiaries, and by certain of its future subsidiaries. The senior notes and the guarantees are unsecured and rank equally with all of the Partnership’s and the guarantors’ existing and future unsecured obligations. The senior notes and the guarantees will be senior in right of payment to any of the Partnership’s and the guarantors’ future obligations that are, by their terms, expressly subordinated in right of payment to the notes and the guarantees. The senior notes and the guarantees will be effectively subordinated to the Partnership’s and the guarantors’ secured obligations, including the Partnership’s revolving credit facility, to the extent of the value of the assets securing such obligations.

7. 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 took place on April 24, 2012. A decision is not expected for at least several months.

8. Series A Preferred Units

On September 2, 2009, the Partnership issued 4,371,586 Series A Preferred Units. As of September 30, 2012, the Series A Preferred Units were convertible to 4,651,884 common units, and if outstanding, are mandatorily redeemable on September 2, 2029 for $80 million plus all accrued but unpaid distributions and interest thereon. The Series A Preferred Units receive fixed quarterly cash distributions of $0.445 per unit if outstanding on the record dates of the Partnership’s common unit distributions. Holders can elect to convert Series A Preferred Units to common units at any time in accordance with the partnership agreement.

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The following table provides a reconciliation of the beginning and ending balances of the Series A Preferred Units for the nine months ended September 30, 2012:

	Units	Amount	
Outstanding at beginning of period	4,371,586	$71,144	
Accretion to redemption value	—	1,405	
Outstanding at end of period	4,371,586	$72,549	*

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

9. Related Party Transactions

Transactions with ETE and its subsidiaries. Under the service agreement with Services Co., the Partnership pays Services Co.'s direct expenses for services performed, 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 which expires May 26, 2015, subject to earlier termination rights in the event of a change in control, the failure to achieve certain cost savings for the Partnership or upon an event of default. The Partnership also, together with the General Partner 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 automatically renews on a year-to-year basis upon expiration of the initial term. The Partnership incurred total service fees of $4.3 million and $4.2 million for the three months ended September 30, 2012 and 2011, respectively, and $12.9 million and $12.4 million for the nine months ended September 30, 2012 and 2011, respectively.

In conjunction with distributions by the Partnership on the basis of limited and general partner interests, ETE received cash distributions of $15.5 million and $14.4 million for the three months ended September 30, 2012 and 2011, respectively, and $46.4 million and $42.5 million for the nine months ended September 30, 2012 and 2011, respectively.

The Partnership's Gathering and Processing segment, in the ordinary course of business, gathers, processes, transports and sells natural gas and NGLs to subsidiaries of ETE and records the revenue in gas sales and NGL sales. The Partnership's Contract Compression segment provides contract compression services to subsidiaries of ETP and records revenue in gathering, transportation and other fees. The Partnership's Contract Compression segment sold compression equipment to a subsidiary of ETP for $0.3 million and $1.6 million for the three months ended September 30, 2012 and 2011, respectively, and $1.1 million and $7.9 million for the nine months ended September 30, 2012 and 2011. The Partnership's Contract Compression segment purchased compression equipment from a subsidiary of ETP for $6.2 million and $24.3 million for the three and nine months ended September 30, 2011, respectively. During 2012, the Partnership's Contract Compression segment has made no purchases of compression equipment from subsidiaries of ETP.

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. Reimbursements were recorded to the General Partner for $12.9 million and $12.6 million during the three months ended September 30, 2012 and 2011, respectively, and $37.8 million and $47 million during the nine months ended September 30, 2012 and 2011, respectively, in the Partnership's financial statements as operating expenses or general and administrative expenses. Reimbursements were also recorded to ETP for $9.4 million and $6.2 million during the three months ended September 30, 2012 and 2011, respectively, and $23.9 million and $14.8 million during the nine months ended September 30, 2012 and 2011, respectively, 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. Related party general and administrative expenses reimbursed to the Partnership were $5.1 million and $4.2 million for the three months ended September 30, 2012 and 2011, respectively, and $14.4 million and $12.6 million for the nine months ended September 30, 2012 and 2011, respectively, which are recorded in gathering, transportation and other fees.

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

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10. Segment Information

The Partnership has the following five reportable segments:

Gathering and Processing. The Partnership provides “wellhead-to-market” services to producers of natural gas, which include transporting raw natural gas from the wellhead through gathering systems, processing raw natural gas to separate NGLs from the raw natural gas and selling or delivering pipeline-quality natural gas and NGLs to various markets and pipeline systems. This segment also includes the Partnership's investment in Ranch JV, which processes natural gas delivered from the NGLs-rich Bone Spring and Avalon shale formations in west Texas. The Partnership initially included Ranch JV in the Joint Ventures segment upon formation in December 2011 until March 31, 2012, during which time Ranch JV's only activity was the construction of capital projects.

Joint Ventures. The Partnership's Joint Ventures segment includes the following:

- 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;
- a 50% membership 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; and
- a 30% membership interest in Lone Star, an entity owning a diverse set of midstream energy assets including NGL pipelines, storage, fractionation 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 small regulated 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, revenue generating horsepower and revenue generating gallons per minute. Operation and maintenance expenses are a separate measure used by management to evaluate performance of field operations. Direct labor, insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of operation and maintenance expenses. These expenses fluctuate depending on the activities performed during a specific period. The Partnership does not deduct operation and maintenance expenses from total revenues in calculating segment margin because management separately evaluates commodity volume and price changes in segment margin.

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Results for each segment are shown below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
External Revenues				
Gathering and Processing	$262,087	$339,273	$832,354	$908,448
Joint Ventures [1]	—	—	—	—
Contract Compression	37,841	36,024	111,279	112,532
Contract Treating	8,707	10,573	25,230	29,848
Corporate and Others	5,247	4,397	14,894	13,189
Eliminations	—	—	—	—
Total	$313,882	$390,267	$983,757	$1,064,017
Intersegment Revenues				
Gathering and Processing	$—	$—	$—	$—
Joint Ventures [1]	—	—	—	—
Contract Compression	4,407	3,339	12,968	12,809
Contract Treating	1,092	20	2,271	20
Corporate and Others	58	60	167	237
Eliminations	(5,557)	(3,419)	(15,406)	(13,066)
Total	$—	$—	$—	$—
Segment Margin				
Gathering and Processing	$59,392	$64,716	$210,143	$169,011
Joint Ventures [1]	—	—	—	—
Contract Compression	39,380	37,957	116,381	116,370
Contract Treating	8,115	6,642	23,239	21,594
Corporate and Others	5,459	4,767	15,604	14,582
Eliminations	(5,345)	(3,341)	(14,959)	(12,802)
Total	$107,001	$110,741	$350,408	$308,755
Operation and Maintenance				
Gathering and Processing	$30,226	$24,426	$87,240	$67,250
Joint Ventures [1]	—	—	—	—
Contract Compression	15,099	15,916	45,648	48,618
Contract Treating	1,180	902	2,846	2,311
Corporate and Others	115	41	473	129
Eliminations	(5,345)	(3,335)	(14,959)	(12,802)
Total	$41,275	$37,950	$121,248	$105,506

(1) The Partnership does not record segment margin or operation and maintenance expenses for the Joint Ventures segment because it records its ownership percentages of the net income of its unconsolidated affiliates as income from unconsolidated affiliates in accordance with the equity method of accounting.

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The table below provides a reconciliation of total segment margin to income before income taxes:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Total segment margin	$107,001	$110,741	$350,408	$308,755
Operation and maintenance	(41,275)	(37,950)	(121,248)	(105,506)
General and administrative	(14,935)	(17,350)	(47,106)	(54,010)
Gain (loss) on asset sales, net	42	131	(1,542)	(50)
Depreciation and amortization	(45,881)	(41,956)	(142,519)	(122,695)
Income from unconsolidated affiliates	21,055	30,946	87,198	86,921
Interest expense, net	(28,567)	(28,852)	(86,058)	(73,548)
Loss on debt refinancing, net	—	—	(7,820)	—
Other income and deductions, net	1,106	15,050	25,549 *	20,105
(Loss) income before income taxes	$(1,454)	$30,760	$56,862	$59,972

* Other income and deductions, net for the nine months ended September 30, 2012, included a one-time producer payment of $15.6 million related to an assignment of certain contracts.

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

	September 30, 2012	December 31, 2011
Gathering and Processing	$2,127,565	$1,959,697
Joint Ventures	2,123,802	1,924,705
Contract Compression	1,421,377	1,405,600
Contract Treating	228,940	215,172
Corporate and Others	66,452	62,682
Total	$5,968,136	$5,567,856

11. Equity-Based Compensation

The Partnership's LTIP for its employees, directors and consultants authorizes grants up to 5,865,584 common units. LTIP compensation expense of $1.2 million and $0.7 million, is recorded in general and administrative expense for the three months ended September 30, 2012 and 2011, respectively, and $3.5 million and $2.4 million for the nine months ended September 30, 2012 and 2011, respectively.

Common Unit Options. There was no common unit option activity for the nine months ended September 30, 2012. The aggregate intrinsic value and weighted average contractual term in years as of September 30, 2012 for the outstanding and exercisable common unit options was $0.3 million and 3.6 years, respectively. During the nine months ended September 30, 2011, the Partnership received $0.8 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 18 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 nine months ended September 30, 2012:

Phantom Units	Units		Weighted Average Grant Date Fair Value
Outstanding at beginning of period	1,086,393		$ 24.51
Service condition grants	8,250		24.18
Vested service condition	(29,553	)	23.33
Vested market condition	(10,200	)	19.52
Forfeited service condition	(92,468	)	24.86
Forfeited market condition	(4,350	)	19.52
Outstanding at end of period	958,072		24.58

The Partnership expects to recognize $16.3 million of compensation expense related to non-vested phantom units over a period of 3.6 years.

12. Fair Value Measures

The Partnership's financial assets and liabilities measured at fair value on a recurring basis are derivatives related to interest rate swaps, commodity swaps, ethane put options and embedded derivatives in the Series A Preferred Units. Derivatives related to interest rate swaps, commodity swaps and ethane put options 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. Embedded 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 September 30, 2012			Fair Value Measurements at December 31, 2011		
	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	$1,238	$1,238	$—	$ 3,907	$ 3,907	$—
NGLs	3,927	3,927	—	94	94	—
Condensate	2,510	2,510	—	538	538	—
Ethane - Put Options	1,030	1,030	—	309	309	—
Total Assets	$8,705	$8,705	$—	$ 4,848	$ 4,848	$—
Liabilities:						
Interest Rate Derivatives	$—	$—	$—	$ 470	$ 470	$—
Commodity Derivatives:						
Natural Gas	923	923	—	—	—	—
NGLs	276	276	—	8,561	8,561	—
Condensate	—	—	—	1,567	1,567	—
Embedded Derivatives in Series A Preferred Units	29,094	—	29,094	39,049	—	39,049
Total Liabilities	$30,293	$1,199	$ 29,094	$ 49,647	$ 10,598	$ 39,049

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The following table presents the material unobservable inputs used to estimate the fair value of the embedded derivatives in the Series A Preferred Units:

Unobservable Input	September 30, 2012	
Credit Spread	6.31	%
Volatility	18.32	%

Changes in the Partnership's cost of equity and U.S. Treasury yields would cause a change in the credit spread used to value the embedded derivatives. Changes in the Partnership's historical unit price volatility would cause a change in the volatility used to value the embedded derivatives.

The following table presents the changes in Level 3 derivatives measured on a recurring basis for the nine months ended September 30, 2012. There were no transfers between the fair value hierarchy levels for the nine months ended September 30, 2012.

	Embedded Derivatives in Series A Preferred Units	
Outstanding balance at beginning of period	$39,049	
Change in fair value	(9,955	)
Outstanding balance at end of period	$29,094	

The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximate 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 aggregate fair value and carrying amount of our senior notes at September 30, 2012 was $1.36 billion and $1.26 billion, respectively. As of December 31, 2011, the aggregate fair value and carrying amount of our senior notes was $1.44 billion and $1.35 billion, respectively. The fair value of our senior notes are a Level 1 valuation based on third party market value quotations.

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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 condensed 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 and processing, contract compression, treating and transportation of natural gas and the transportation, fractionation and storage of NGLs. We focus on providing midstream services in some of the most prolific natural gas producing regions in the United States, including the Eagle Ford, Haynesville, Barnett, Fayetteville, Marcellus, Bone Spring and Avalon shales and the mid-continent region. Our assets are located in Texas, Louisiana, Arkansas, Pennsylvania, California, Mississippi, Alabama, West Virginia and the mid-continent region of the United States, which includes Kansas, Colorado and Oklahoma.

RECENT DEVELOPMENTS. In May 2012, we announced the construction of an expansion to Edwards Lime in the Eagle Ford shale ("Edwards Lime Expansion") which will increase the system's capacity by 90 MMcf/d to 160 MMcf/d, and will provide for additional crude transportation and stabilization capacity of 17,000 Bbls/d. We own a 60% interest in Edwards Lime and operate the assets. Contracts on the expansion are fee-based, which includes reservation fees. Capital expenditures related to the expansion are expected to total $150 million, of which we will contribute $90 million; this amount is included in our previously announced 2012 growth capital projections. The project is expected to be completed in the fourth quarter of 2012.

In August 2012, we announced an expansion of the Dubach processing facility in north Louisiana which will increase the processing capacity of the facility to 210 MMcf/d by adding an incremental 70 MMcf/d of cryogenic processing capacity and 20 MMcf/d of JT capacity. The $75 million capital expenditure related to the Dubach expansion also includes the construction of high-pressure gathering lines to bring production to the facility. The project, which is expected to come online in the second quarter of 2013, is backed by fee-based contracts and an acreage dedication.

Ranch JV. In June 2012, Ranch JV's refrigeration processing plant became operational.

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 transporting raw natural gas from the wellhead through gathering systems, processing raw natural gas to separate NGLs from the raw natural gas and selling or delivering the pipeline-quality natural gas and NGLs to various markets and pipeline systems. This segment also includes our investment in Ranch JV, which processes natural gas delivered from the NGLs-rich Bone Spring and Avalon shale formations in west Texas.
- Joint Ventures. Our Joint Ventures segment includes the following:

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;

a 50% membership 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; and

a 30% membership interest in Lone Star, an entity owning a diverse set of midstream energy assets including NGL pipelines, storage, fractionation 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 regulated pipeline and our corporate offices.

HOW WE EVALUATE OUR OPERATIONS. Management uses a variety of financial and operational measures 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 and operation and maintenance expense on a segment and company-wide basis and EBITDA and adjusted EBITDA on a 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, generally, as revenues minus cost of sales. We calculate our Gathering and Processing segment margin and Corporate and Others segment margin as our revenues generated from operations 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 of our unconsolidated affiliates as income from unconsolidated affiliates in accordance with the equity method of accounting.

We calculate our Contract Compression segment margin as our revenues generated from our contract compression operations minus direct costs, primarily compressor unit repairs, associated with those revenues.

We calculate our Contract Treating segment margin as revenues generated from our contract treating operations minus direct costs associated with those revenues.

We calculate total segment margin as the total of segment margin of our 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. 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 because they represent the results of product purchases and sales, a key component of our operations.

Revenue Generating Horsepower. Revenue generating horsepower is the primary driver for revenue growth in our contract compression segment, and it is also the primary measure for evaluating our operational efficiency. Revenue generating horsepower is 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 the treating business in 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 revenues.

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 use segment margin to separately evaluate commodity volume and price changes.

EBITDA and Adjusted EBITDA. We define EBITDA as net income (loss) plus interest expense, net, income tax expense 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 expenses;
- loss (gain) on asset sales, net;
- loss on debt refinancing, net;
- other non-cash (income) expense, net;
- net income attributable to noncontrolling interest; and
- our 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.

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 for the Partnership:

	Nine Months Ended September 30,	
Reconciliation of “Adjusted EBITDA” to net cash flows provided by operating activities and net income	2012	2011
Net cash flows provided by operating activities	$180,925	$204,416
Add (deduct):		
Depreciation and amortization, including debt issuance cost and bond premium amortization	(146,913)	(127,079)
Income from unconsolidated affiliates	87,198	86,921
Derivative valuation changes	17,124	21,660
Loss on asset sales, net	(1,542)	(50)
Unit-based compensation expenses	(3,470)	(2,444)
Trade accounts receivable, accrued revenues and related party receivables	(10,779)	13,298
Other current assets	1,429	(186)
Trade accounts payable, accrued cost of gas and liquids, related party payables and deferred revenues	31,675	(20,467)
Other current liabilities	(7,159)	(24,833)
Distributions received from unconsolidated affiliates	(91,893)	(91,306)
Other assets and liabilities	178	61
Net income	56,773	59,991
Add:		
Interest expense, net	86,058	73,548
Depreciation and amortization expense	142,519	122,695
Income tax expense (benefit)	89	(19)
EBITDA	285,439	256,215
Add (deduct):		
Non-cash gain from commodity and embedded derivatives	(16,650)	(20,149)
Unit-based compensation expenses	3,470	2,687
Loss on asset sales, net	1,542	50
Loss on debt refinancing, net	7,820	—
Income from unconsolidated affiliates	(87,198)	(86,921)
Partnership’s interest in unconsolidated affiliates' adjusted EBITDA	170,582	156,000
Other expense (income), net	(1,462)	(413)
Adjusted EBITDA	$363,543	$307,469

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The following tables present reconciliations of net income to adjusted EBITDA for our unconsolidated affiliates, on a 100% basis, and the Partnership's interest in adjusted EBITDA for the nine months ended September 30, 2012 and 2011:

	Nine Months Ended September 30, 2012				
	HPC	MEP	Lone Star	Ranch JV	Total
Net income (loss)	$55,364	$62,606	$109,712	$(931)	
Add:					
Depreciation and amortization	27,354	52,075	37,737	768	
Impairment of property, plant and equipment	14,114	—	—	—	
Interest expense, net	1,397	38,609	—	—	
Other expense (income)	1,285	(4)	36	—	
Adjusted EBITDA	99,514	153,286	147,485	(163)	
Ownership interest	49.99%	50%	30%	33.33%	
Partnership's interest in adjusted EBITDA	$49,747	$76,643	$44,246	$(54)	$170,582

	Nine Months Ended September 30, 2011				
	HPC	MEP	Lone Star(1)	Ranch JV	Total
Net income	$84,703	$62,684	58,910	N/A	
Add:					
Depreciation and amortization	25,846	52,176	20,043	N/A	
Interest expense, net	782	38,623	—	N/A	
Other expense, net	16	—	169	N/A	
Adjusted EBITDA	111,347	153,483	79,122	N/A	
Average ownership interest	49.99%	49.9%	30%	N/A	
Partnership's interest in adjusted EBITDA	$55,660	$76,604	$23,736	N/A	$156,000

(1) For the period from initial contribution, May 2, 2011, to September 30, 2011.
N/A We acquired a 33.33% membership interest in Ranch JV in December 2011.

The following table presents a reconciliation of total segment margin and adjusted total segment margin to net income for the three and nine month periods ended September 30, 2012 and 2011 for the Partnership:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Net (loss) income	$(1,454)	$30,849	$56,773	$59,991
Add (deduct):				
Operation and maintenance	41,275	37,950	121,248	105,506
General and administrative	14,935	17,350	47,106	54,010
(Gain) loss on asset sales, net	(42)	(131)	1,542	50
Depreciation and amortization	45,881	41,956	142,519	122,695
Income from unconsolidated affiliates	(21,055)	(30,946)	(87,198)	(86,921)
Interest expense, net	28,567	28,852	86,058	73,548
Loss on debt refinancing, net	—	—	7,820	—
Other income and deductions, net	(1,106)	(15,050)	(25,549)	(20,105)
Income tax (benefit) expense	—	(89)	89	(19)
Total segment margin	107,001	110,741	350,408	308,755
Add (deduct):				
Non-cash loss (gain) from commodity derivatives	8,877	174	(6,695)	606

Adjusted total segment margin	$115,878	$110,915	$343,713	$309,361

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Three Months Ended September 30, 2012 vs. Three Months Ended September 30, 2011

	Three Months Ended September 30,			
	2012	2011	Change	Percent
Total revenues	$313,882	$390,267	$(76,385)	20 %
Cost of sales	206,881	279,526	72,645	26
Total segment margin [1]	107,001	110,741	(3,740)	3
Operation and maintenance	41,275	37,950	(3,325)	9
General and administrative	14,935	17,350	2,415	14
Gain on asset sales, net	(42)	(131)	(89)	68
Depreciation and amortization	45,881	41,956	(3,925)	9
Operating income	4,952	13,616	(8,664)	64
Income from unconsolidated affiliates	21,055	30,946	(9,891)	32
Interest expense, net	(28,567)	(28,852)	285	1
Other income and deductions, net	1,106	15,050	(13,944)	93
(Loss) income before income taxes	(1,454)	30,760	(32,214)	105
Income tax expense (benefit)	—	(89)	(89)	100
Net (loss) income	(1,454)	30,849	(32,303)	105
Net income attributable to noncontrolling interest	(379)	(549)	170	31
Net (loss) income attributable to Regency Energy Partners LP	$(1,833)	$30,300	$(32,133)	106
Gathering and processing segment margin	$59,392	$64,716	$(5,324)	8
Non-cash loss from commodity derivatives	8,877	174	8,703	5,002
Adjusted gathering and processing segment margin	68,269	64,890	3,379	5
Contract compression segment margin [2]	39,380	37,957	1,423	4
Contract treating segment margin [2]	8,115	6,642	1,473	22
Corporate and others segment margin	5,459	4,767	692	15
Intersegment eliminations [2]	(5,345)	(3,341)	(2,004)	60
Adjusted total segment margin	$115,878	$110,915	$4,963	4 %

(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) Contract Compression and Contract Treating segment margin includes intersegment revenues of $4.3 million and $1.1 million, respectively, for the three months ended September 30, 2012 and $3.3 million and $0.0 million, respectively, for the three months ended September 30, 2011. These intersegment revenues were eliminated upon consolidation.

Net (Loss) Income Attributable to Regency Energy Partners LP. We had a net loss of $1.8 million for the three months ended September 30, 2012 compared to the net income of $30.3 million for the three months ended September 30, 2011. The major components of this change were as follows:

- $13.9 million decrease in other income and deductions, net primarily due to a 2011 non-cash mark-to-market gain recorded on the embedded derivative related to the Series A Units;
- $9.9 million decrease in income from unconsolidated affiliates primarily related to a non-cash asset impairment charge related to HPC's surplus equipment;
- $3.7 million decrease in total segment margin primarily due to the non-cash mark-to-market loss on outstanding derivatives during the quarter ending September 30, 2012 as we de-designated our swap contracts and began accounting for these contracts using the mark-to-market method of accounting beginning January 1, 2012. Although the decline in commodity prices lowered revenues and cost of sales, it had little impact to our total segment margin, as

we try to match sales price of commodities with purchases to reduce commodity price risk;

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- $3.9 million increase in depreciation and amortization expense primarily related to the completion of various organic growth projects since October 2011; and
- $3.3 million increase in operation and maintenance expenses primarily related to an increase in pipeline and plant operating expenses associated with increased activity in south and west Texas; offset by
- $2.4 million decrease in general and administrative expenses primarily due to decreases in office and legal expenses as well as insurance expenses.

Adjusted Total Segment Margin. Adjusted total segment margin increased to $115.9 million in the three months ended September 30, 2012 from $110.9 million in the three months ended September 30, 2011. The major components of this change were as follows:

- Adjusted Gathering and Processing segment margin increased to $68.3 million during the three months ended September 30, 2012 from $64.9 million for the three months ended September 30, 2011 primarily due to volume growth in south and west Texas and north Louisiana. Total Gathering and Processing throughput increased to 1,461,000 MMBtu/d during the three months ended September 30, 2012 from 1,293,000 MMBtu/d during the three months ended September 30, 2011. Total NGL gross production increased to 36,000 Bbls/d during the three months ended September 30, 2012 from 35,000 Bbls/d during the three months ended September 30, 2011;
- Contract Compression segment margin increased to $39.4 million in the three months ended September 30, 2012 from $38 million in the three months ended September 30, 2011. Contract Compression segment margin includes both revenues from external customers as well as intersegment revenues. The increase in segment margin is primarily due to the increase in revenue generating horsepower, inclusive of intersegment revenue generating horsepower. Revenue generating horsepower, inclusive of intersegment revenue generating horsepower, increased to 873,000 as of September 30, 2012 from 836,000 as of September 30, 2011. The increase in revenue generating horsepower is primarily attributable to additional horsepower placed into service in south Texas for the Gathering and Processing segment to provide compression services to external customers;
- Contract Treating segment margin increased to $8.1 million for the three months ended September 30, 2012 from $6.6 million for the three months ended September 30, 2011. Revenue generating GPM as of September 30, 2012 and September 30, 2011 was 3,910 and 3,468, respectively; and
- Intersegment eliminations increased to $5.3 million in the three months ended September 30, 2012 from $3.3 million in the three months ended September 30, 2011. The increase was primarily due to an increase in transactions between the Gathering and Processing and the Contract Compression and Contract Treating segments as a result of additional horsepower and treating services placed into service in south Texas for the Gathering and Processing segment to provide compression and treating services to external customers.

Operation and Maintenance. Operation and maintenance expense increased to $41.3 million in the three months ended September 30, 2012 from $38 million during the three months ended September 30, 2011. The change was primarily due to the following:

- $1.6 million increase in pipeline and plant operating expenses primarily related to increased activity in south and west Texas; and
- $1.3 million increase in compressor maintenance expense primarily due to increases in maintenance and materials costs.

General and Administrative. General and administrative expense decreased to $14.9 million in the three months ended September 30, 2012 from $17.4 million during the three months ended September 30, 2011. The change was primarily due to the following:

- $1.4 million decrease in office expenses and legal fees; and
- $1.1 million decrease in insurance expenses primarily due to reductions in premiums.

Depreciation and Amortization. Depreciation and amortization expense increased to $45.9 million in the three months ended September 30, 2012 from $42 million in the three months ended September 30, 2011. This increase was the result of additional depreciation and amortization expense due to the completion of various organic growth projects since October 2011.

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Income from Unconsolidated Affiliates. Income from unconsolidated affiliates decreased to $21.1 million for the three months ended September 30, 2012 from $30.9 million for the three months ended September 30, 2011. The schedule below summarizes the components of income from unconsolidated affiliates and our ownership interest for the three months ended September 30, 2012 and 2011, respectively:

	Three Months Ended September 30, 2012				
	HPC	MEP	Lone Star	Ranch JV	Total
Net income (loss)	$6,520	$20,735	$30,611	$(880)	
Ownership interest	49.99%	50%	30%	33.33%	
Share of unconsolidated affiliates' net income (loss)	3,259	10,367	9,184	(293)	
Less: Amortization of excess fair value of unconsolidated affiliates	(1,462)	—	—	—	
Income (loss) from unconsolidated affiliates	$1,797	$10,367	$9,184	$(293)	$21,055

	Three Months Ended September 30, 2011				
	HPC	MEP	Lone Star(1)	Ranch JV	Total
Net income	$24,282	$21,998	$30,952	N/A	
Average ownership interest	49.99%	49.9%	30%	N/A	
Share of unconsolidated affiliates' net income	12,138	10,985	9,285	N/A	
Less: Amortization of excess fair value of unconsolidated affiliates	(1,462)	—	—	N/A	
Income from unconsolidated affiliates	$10,676	$10,985	$9,285	N/A	$30,946

(1) For the period from initial contribution, May 2, 2011, to September 30, 2011.
N/A We acquired a 33.33% membership interest in Ranch JV in December 2011.

HPC's net income decreased to $6.5 million for the three months ended September 30, 2012 from $24.3 million for the three months ended September 30, 2011, primarily due to a non-cash asset impairment charge related to its surplus equipment acquired during RIGS' 2009 Haynesville Expansion Project and not anticipated to be utilized in future expansion projects, the expiration of certain contracts not renewed and lower throughput. Shippers who are choosing not to renew their contracts are primarily doing so because they hold excess firm transportation capacity out of the Haynesville shale. This excess capacity is a result of moving drilling rigs out of the Haynesville area to richer gas plays which has slowed supply growth and contributed to the decrease in throughput. MEP's net income decreased to $20.7 million for the three months ended September 30, 2012 from $22 million for the three months ended September 30, 2011, primarily due to the loss of a shipper contract. Lone Star's net income decreased to $30.6 million for the three months ended September 30, 2012 from $31 million for the three months ended September 30, 2011, which was primarily caused by the temporary down time in its refinery services operation in September 2012 due to Hurricane Isaac.

The following table presents operational data for each of our unconsolidated affiliates for the three months ended September 30, 2012 and 2011:

		Three Months Ended September 30,	
	Operational data	2012	2011
HPC	Throughput (MMBtu/d)	826,974	1,192,203
MEP	Throughput (MMBtu/d)	1,391,605	1,320,480
Lone Star	West Texas Pipeline – Throughput (Bbls/d)(1)	132,297	133,149
	NGL Fractionation Throughput (Bbls/d) (1)	11,073	13,833
Ranch JV	Throughput (MMBtu/d) (2)	863	N/A

(1) Lone Star's operational volumes represent the period from initial contribution, May 2, 2011, to September 30, 2011.
(2) Ranch JV began operations in June 2012.
N/A We acquired a 33.33% membership interest in Ranch JV in December 2011.

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Other Income and Deductions, Net. Other income and deductions, net decreased to $1.1 million in the three months ended September 30, 2012 from $15.1 million in the three months ended September 30, 2011, primarily due to the non-cash mark-to-market gain in the embedded derivative related to the Series A Units.

RESULTS OF OPERATIONS

Nine Months Ended September 30, 2012 vs. Nine Months Ended September 30, 2011

	Nine Months Ended September 30,			
	2012	2011	Change	Percent
Total revenues	$983,757	$1,064,017	$(80,260)	8 %
Cost of sales	633,349	755,262	121,913	16
Total segment margin (1)	350,408	308,755	41,653	13
Operation and maintenance	121,248	105,506	(15,742)	15
General and administrative	47,106	54,010	6,904	13
Loss on asset sales, net	1,542	50	(1,492)	2,984
Depreciation and amortization	142,519	122,695	(19,824)	16
Operating income	37,993	26,494	11,499	43
Income from unconsolidated affiliates	87,198	86,921	277	—
Interest expense, net	(86,058)	(73,548)	(12,510)	17
Loss on debt refinancing, net	(7,820)	—	(7,820)	100
Other income and deductions, net	25,549	20,105	5,444	27
Income before income taxes	56,862	59,972	(3,110)	5
Income tax expense (benefit)	89	(19)	(108)	568
Net income	56,773	59,991	(3,218)	5
Net income attributable to noncontrolling interest	(1,427)	(1,073)	(354)	33
Net income attributable to Regency Energy Partners LP	$55,346	$58,918	$(3,572)	6
Gathering and processing segment margin	$210,143	$169,011	$41,132	24
Non-cash (gain) loss from commodity derivatives	(6,695)	606	(7,301)	1,205
Adjusted gathering and processing segment margin	203,448	169,617	33,831	20
Contract compression segment margin (2)	116,381	116,370	11	—
Contract treating segment margin (2)	23,239	21,594	1,645	8
Corporate and others segment margin	15,604	14,582	1,022	7
Intersegment eliminations (2)	(14,959)	(12,802)	(2,157)	17
Adjusted total segment margin	$343,713	$309,361	$34,352	11 %

(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) Contract Compression and Contract Treating segment margin includes intersegment revenues of $12.8 million and $2.2 million, respectively, for the nine months ended September 30, 2012 and $12.8 million and $0 million, respectively, for the nine months ended September 30, 2011. These intersegment revenues were eliminated upon consolidation.

Net Income Attributable to Regency Energy Partners LP. Our income decreased to $55.3 million for the nine months ended September 30, 2012 from $58.9 million for the nine months ended September 30, 2011. The major components of this change were as follows:

- $41.7 million increase in total segment margin primarily due to increased volumes in south and west Texas and north Louisiana in our Gathering and Processing segment. Although the decline in commodity prices lowered revenues and cost of sales, it had little impact to our total segment margin, as we try to match sales price of commodities with purchases to reduce commodity price risk. In addition, the decrease in commodity revenues was partially offset by an increase gathering and processing fees, as we continue to grow our fee-based revenues in south and west Texas as well as north Louisiana;

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- $6.9 million decrease in general and administrative expenses primarily due to lower employee, professional fees and insurance and office expenses;
- $5.4 million increase in other income and deductions, net primarily due to a $15.6 million one-time producer payment received in March 2012 related to an assignment of certain contracts as well as an increase in the non-cash mark-to-market gain in the embedded derivative related to the Series A Units; offset by
- $19.8 million increase in depreciation and amortization expense primarily related to the completion of various organic growth projects since October 2011, as well as an out of period adjustment of $6.9 million recorded in March 2012 (further discussed below);
- $15.7 million increase in operation and maintenance expense primarily related to increased pipeline and plant operating expenses associated with increased activity in south and west Texas;
- $12.5 million increase in interest expense primarily related to the interest associated with the $500 million senior notes we issued in May 2011; and
- $7.8 million net loss on debt refinancing related to the redemption of 35% of our outstanding senior notes due 2016 at a price of 109.375% of the principal amount plus accrued interest in May 2012.

Adjusted Total Segment Margin. Adjusted total segment margin increased to $343.7 million in the nine months ended September 30, 2012 from $309.4 million in the nine months ended September 30, 2011. The major components of this change were as follows:

- Adjusted Gathering and Processing segment margin increased to $203.4 million during the nine months ended September 30, 2012 from $169.6 million for the nine months ended September 30, 2011 primarily due to volume growth in south and west Texas and north Louisiana. Total Gathering and Processing throughput increased to 1,409,000 MMBtu/d during the nine months ended September 30, 2012 from 1,132,000 MMBtu/d during the nine months ended September 30, 2011. Total NGL gross production increased to 37,000 Bbls/d during the nine months ended September 30, 2012 from 30,000 Bbls/d during the nine months ended September 30, 2011;
- Contract Compression segment margin remained unchanged in the nine months ended September 30, 2012 and September 30, 2011. Contract Compression segment margin includes both revenues from external customers as well as intersegment revenues. The slight increase in segment margin is primarily due to the transfer of certain compression units from the Contract Compression segment to the Gathering and Processing segment in the nine months ended September 30, 2011, offset by the increase in revenue generating horsepower, inclusive of intersegment revenue generating horsepower. Revenue generating horsepower, inclusive of intersegment revenue generating horsepower, increased to 873,000 as of September 30, 2012 from 836,000 as of September 30, 2011. The increase in revenue generating horsepower is primarily attributable to additional horsepower placed into service in south Texas for the Gathering and Processing segment to provide compression services to external customers;
- Contract Treating segment margin increased to $23.2 million for the nine months ended September 30, 2012 from $21.6 million for the nine months ended September 30, 2011. Revenue generating GPM as of September 30, 2012 and September 30, 2011 was 3,910 and 3,468, respectively; and
- Intersegment eliminations increased to $15 million in the nine months ended September 30, 2012 from $12.8 million in the nine months ended September 30, 2011. The increase was primarily due to an increase in transactions between the Gathering and Processing and the Contract Compression and Treating segments as a result of additional services provided in south Texas for the Gathering and Processing segment to provide compression and treating services to external customers.

Operation and Maintenance. Operation and maintenance expense increased to $121.2 million in the nine months ended September 30, 2012 from $105.5 million during the nine months ended September 30, 2011. The change was primarily due to the following:

- $8.9 million increase in pipeline and plant operating expenses primarily related to increased activity in south and west Texas;
- $4.6 million increase in compressor maintenance expense primarily due to an increase in maintenance and materials costs; and
- $2.8 million increase in employee related costs primarily due to organic growth projects in south and west Texas.

General and Administrative. General and administrative expense decreased to $47.1 million in the nine months ended September 30, 2012 from $54 million during the nine months ended September 30, 2011. The change was primarily due to the following:

- $2.6 million decrease in insurance and office costs primarily due to reductions in premiums and lower rent expense;
- $2 million decrease in professional fees related to lower legal and investor relations fees; and

•$1.6 million decrease related to the shared services integration and subsequent reduction in employee headcount.

Depreciation and Amortization. Depreciation and amortization expense increased to $142.5 million in the nine months ended September 30, 2012 from $122.7 million in the nine months ended September 30, 2011. This increase was the result of $12.9 million of additional depreciation and amortization expense due to the completion of various organic growth projects since October 2011 and $6.9 million related to an “out-of-period” adjustment for all periods subsequent to May 26, 2010 (the “Successor” periods as described in our Form 10-K for the year ended December 31, 2011) related to our Contract Compression segment to adjust the estimated useful lives of certain assets to comply with our policy. The amounts related to the year ended December 31, 2011 and to the period from May 26, 2010 to December 31, 2010 were $4.4 million and $2.5 million, respectively. Had these amounts been recorded to their respective period, the depreciation and amortization expense for the nine months ended September 30, 2012 and 2011 would have been $135.6 million and $126 million, respectively.

Income from Unconsolidated Affiliates. Income from unconsolidated affiliates increased to $87.2 million for the nine months ended September 30, 2012 from $86.9 million for the nine months ended September 30, 2011. The schedule below summarizes the components of income from unconsolidated affiliates and our ownership interest for the nine months ended September 30, 2012 and 2011, respectively:

	Nine Months Ended September 30, 2012				
	HPC	MEP	Lone Star	Ranch JV	Total
Net income (loss)	$55,364	$62,606	$109,712	$(931)	
Ownership interest	49.99%	50%	30%	33.33%	
Share of unconsolidated affiliates’ net income (loss)	27,676	31,303	32,914	(310)	
Less: Amortization of excess fair value of unconsolidated affiliates	(4,385)	—	—	—	
Income (loss) from unconsolidated affiliates	$23,291	$31,303	$32,914	$(310)	$87,198

	Nine Months Ended September 30, 2011				
	HPC	MEP	Lone Star(1)	Ranch JV	Total
Net income	$84,703	$62,684	$58,910	N/A	
Average ownership interest	49.99%	49.9%	30%	N/A	
Share of unconsolidated affiliates’ net income	42,343	31,290	17,673	N/A	
Less: Amortization of excess fair value of unconsolidated affiliates	(4,385)	—	—	N/A	
Income from unconsolidated affiliates	$37,958	$31,290	$17,673	N/A	$86,921

(1) For the period from initial contribution, May 2, 2011, to September 30, 2011.

N/A We acquired a 33.33% membership interest in Ranch JV in December 2011.

HPC’s net income decreased to $55.4 million for the nine months ended September 30, 2012 from $84.7 million for the nine months ended September 30, 2011, primarily due to a non-cash asset impairment charge related to its surplus equipment acquired during RIGS' 2009 Haynesville Expansion Project and not anticipated to be utilized in future expansion projects, the expiration of certain contracts not renewed and lower throughput. Shippers who are choosing not to renew their contracts are primarily doing so because they hold excess firm transportation capacity out of the Haynesville shale. This excess capacity is a result of moving drilling rigs out of the Haynesville area to richer gas plays which has slowed supply growth and contributed to the decrease in throughput. MEP's net income decreased to $62.6 million for the nine months ended September 30, 2012 from $62.7 million for the nine months ended September 30, 2011. Lone Star's net income increased to $109.7 million for the nine months ended September 30, 2012 from $58.9 million for the nine months ended September 30, 2011, due to the net income in the prior period only reflecting the activity from initial contribution, May 2, 2011, to September 30, 2011.

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The following table presents operational data for each of our unconsolidated affiliates for the nine months ended September 30, 2012 and 2011:

		Nine Months Ended September 30,	
	Operational data	2012	2011
HPC	Throughput (MMBtu/d)	890,254	1,411,201
MEP	Throughput (MMBtu/d)	1,413,044	1,245,904
Lone Star	West Texas Pipeline – Throughput (Bbls/d) (1)	133,447	131,147
	NGL Fractionation Throughput (Bbls/d) (1)	16,943	14,912
Ranch JV	Throughput (MMBtu/d) (2)	809	N/A

(1) Lone Star's operational volumes represent the period from initial contribution, May 2, 2011, to September 30, 2011.
(2) Ranch JV began operations in June 2012.
N/A We acquired a 33.33% membership interest in Ranch JV in December 2011.

Interest Expense, Net. Interest expense, net increased to $86.1 million for the nine months ended September 30, 2012 from $73.5 million for the nine months ended September 30, 2011 primarily due to the interest related to our $500 million senior notes issued in May 2011 with an interest rate of 6.5%.

Other Income and Deductions, Net. Other income and deductions, net increased to $25.5 million in the nine months ended September 30, 2012 from $20.1 million in the nine months ended September 30, 2011, primarily due to a $15.6 million one-time producer payment received in March 2012 related to an assignment of certain contracts, offset by a decrease in the non-cash mark-to-market gain in the embedded derivative related to the Series A 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, 2011.

OTHER MATTERS

Information regarding our commitments and contingencies is included in Note 7 – Commitments and Contingencies to the condensed consolidated financial statements included in Item 1 of this report.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

We expect our sources of liquidity to include:

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

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We expect our 2012 capital expenditures, including capital contributions to our unconsolidated affiliates, to be as follows (in millions):

	2012
Growth Capital Expenditures	
Gathering and Processing segment [1]	$300
Contract Compression segment	100
Contract Treating segment	40
Joint Ventures segment:	
Lone Star	380
Total	820
Maintenance Capital Expenditures; including our proportionate share related to our joint ventures	$32

(1) Included in the Gathering and Processing segment is $35 million of growth capital expenditures related to the Ranch JV, which represents our portion of the capital contributions to Ranch JV to fund its growth projects.

In 2013, we expect to invest $400 million in growth capital expenditures, of which $185 million is expected to be invested in organic growth projects in the Gathering and Processing segment; $120 million is expected to be invested in our portion of growth capital expenditures for Lone Star; $80 million is expected to be invested in the fabrication of new compressor packages for the Contract Compression segment; and $15 million is expected to be invested in the fabrication of new treating plants for the Contract Treating segment. In addition, we expect to invest $35 million in maintenance capital expenditures in 2013, including our proportionate share related to joint ventures.

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.

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 finance them with long-term debt or equity. 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. The deferred revenue 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 decreased to $4.4 million at September 30, 2012 from $46.2 million at December 31, 2011. The decrease was primarily due to a $35.5 million increase in cash and cash equivalents as a result of the cash contribution into Edwards Lime from its joint venture partners to fund its expansion projects, and a $13.1 million increase in net derivative assets and liabilities driven by the declines in commodity prices.

Cash Flows from Operating Activities. Net cash flows provided by operating activities decreased to $180.9 million in the nine months ended September 30, 2012 from $204.4 million in the nine months ended September 30, 2011. The decrease was primarily due to the net impact of timing of cash receipts and disbursements of $15.3 million, as well as the payment of an $8.2 million redemption premium in 2012 to redeem 35%, or $87.5 million of our $250 million senior notes due 2016.

Cash Flows used in Investing Activities. Net cash flows used in investing activities decreased to $507.1 million in the nine months ended September 30, 2012 from $857.8 million in the nine months ended September 30, 2011, primarily as a result of decreased capital contributions we made to unconsolidated affiliates.

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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 systems or facilities. In the nine months ended September 30, 2012, we incurred $556.7 million of growth capital expenditures. Growth capital expenditures for the nine months ended September 30, 2012 included $194.2 million for organic growth projects for our Gathering and Processing segment, $80.7 million for the fabrication of new compressor packages for our Contract Compression segment, $250.6 million for growth projects for our Joint Ventures segment, and $31.2 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 nine months ended September 30, 2012, we incurred $25.6 million of maintenance capital expenditures.

Cash Flows from Financing Activities. Net cash flows provided by financing activities decreased to $361.6 million in the nine months ended September 30, 2012 from $649.2 million during the same period in 2011. The decrease is primarily due to a $384.5 million decrease in long-term debt borrowings and an increase in partner distributions of $40.7 million, offset by an increase in proceeds from common unit offering of $108.3 million.

Capital Resources

Equity Distribution Agreement. On June 19, 2012, we entered into an Equity Distribution Agreement with Citi under which we may offer and sell common units, representing limited partner interests, having an aggregate offering price of up to $200 million, from time to time through Citi, as our sales agent. Sales of these units, if any, made from time to time under the Equity Distribution Agreement will be made by means of ordinary brokers' transactions on the New York Stock Exchange at market prices, in block transactions, or as otherwise agreed upon by us and Citi. We may also sell common units to Citi as principal for its own account at a price agreed upon at the time of sale. Any sale of common units to Citi as principal would be pursuant to the terms of a separate agreement between the Partnership and Citi. We intend to use the net proceeds from the sale of these units for general partnership purposes. As of September 30, 2012, we have issued 691,129 common units generating $15.4 million in net proceeds.

Common Unit Offering. In March 2012, we issued 12,650,000 common units representing limited partner interests in a public offering at a price of $24.47 per common unit, resulting in net proceeds of $296.8 million. In May 2012, we used the net proceeds from this offering to redeem 35%, or $87.5 million, in aggregate principal amounts of our outstanding senior notes due 2016; pay related premium, expenses and accrued interest; and repay outstanding borrowings under our revolving credit facility.

Senior Notes Redemption. In May 2012, we exercised our option to redeem 35% or $87.5 million of our outstanding senior notes due 2016 at a price of 109.375% of the principal amount plus accrued interest.

Revolving Credit Facility. In August 2012, RGS exercised the accordion feature of the Fifth Amended and Restated Credit Agreement (the "Credit Agreement") to increase its commitments under the revolving credit facility by $250 million to a total of $1.15 billion. The new commitments will be available pursuant to the same terms and subject to the same interest rates and fees as the existing commitments under the Credit Agreement.

Senior Notes Offering. In October 2012, we issued $700 million in senior notes that mature on April 15, 2023. The 2023 Notes bear interest at 5.5% payable semi-annually in arrears on April 15 and October 15, commencing April 15, 2013. The proceeds were used to repay borrowings outstanding under our revolving credit facility.

Cash Distributions from Unconsolidated Affiliates. The following table summarizes the cash distributions received from unconsolidated affiliates for the nine months ended September 30, 2012 and 2011:

	Nine Months Ended September 30,		
	2012	2011	
HPC	$46,468	$49,863	
MEP [1]	56,445	62,897	
Lone Star	38,794	18,900	[2]
	$141,707	$131,660	

(1)

The decrease in MEP distributions is primarily due to an additional payment in 2011 as a result of change in its monthly distribution practice made in January 2011 whereby distributions are now paid concurrently as opposed to a month lag.

(2) For the period from initial contribution, May 2, 2011, to September 30, 2011.

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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 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 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.

The following table sets forth certain information regarding our hedges for natural gas, NGLs and WTI outstanding at September 30, 2012. 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 Amount	Volume/	We Pay	We Receive Weighted Average Price		Fair Value Asset/ (Liability)	Effect of Hypothetical Change in Index*
							(in thousands)	
October 2012-December 2012	Ethane- Put Option	78	(MBbls)	Index	0.65	($/gallon)	1,030	103
October 2012- March 2013	Propane	166	(MBbls)	Index	1.18	($/gallon)	1,673	648
October 2012- September 2013	Normal Butane	163	(MBbls)	Index	1.72	($/gallon)	1,672	1,014
October 2012- March 2013	Natural Gasoline	30	(MBbls)	Index	2.24	($/gallon)	306	255
October 2012- December 2014	West Texas Intermediate Crude	415	(MBbls)	Index	99.46	($/Bbls)	2,510	3,874
October 2012- June 2014	Natural Gas	5,748,000	(MMBtu)	Index	3.88	($/MMBtu)	315	2,198
					Total Fair Value		$7,506	

* 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. These price sensitivity results are presented in absolute terms.

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Item 4. Controls and Procedures

Disclosure controls. At the end of the period covered by this report, an evaluation was performed under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of our General Partner, of the effectiveness of the design and operation of our disclosure controls and procedures (as such terms are defined in Rule 13a–15(e) and 15d–15(e) of the Exchange Act). Based on that evaluation, management, including the Chief Executive Officer and Chief Financial Officer of our General Partner, concluded that our disclosure controls and procedures were effective as of September 30, 2012 to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is properly recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms.

Internal control over financial reporting. There have been no changes in 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 September 30, 2012 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

The information required for this item is provided in Note 7, Commitments and Contingencies, included in the notes to the unaudited condensed consolidated financial statements included under Part I, Item 1, which information is incorporated by reference into this item.

Item 1A. Risk Factors

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, 2011. 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, 2011 and our Quarterly Report on Form 10-Q for the quarter ended March 31, 2012.

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

None.

Item 3. Defaults upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

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Item 6. Exhibits

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

Exhibit 4.1 –	Indenture dated October 27, 2010 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 4.1 to the Partnership's Current Report on Form 8-K filed October 27, 2010).
Exhibit 4.2 –	Fifth Supplemental Indenture dated October 2, 2012 among Regency Energy Partners LP, Regency Energy Finance Corp., the guarantors party thereto and U.S. Bank National Association, as trustee (including the form of the Notes). (Incorporated by reference to Exhibit 4.2 to our current report on Form 8-K dated May 26, 2011.)
Exhibit 10.1 –	Increase Joinder to the Fifth Amended and Restated Credit Agreement dated as of August 22, 2012. (Incorporated by reference to Exhibit 10.1 to our Form 8-K dated August 24, 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 Chief Financial Officer
Exhibit 32.1 –	Section 1350 Certifications of Chief Executive Officer
Exhibit 32.2 –	Section 1350 Certifications of Chief Financial Officer
Exhibit 101.INS –	XBRL Instance Document
Exhibit 101.SCH –	XBRL Taxonomy Extension Schema
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: November 8, 2012

/S/ A. TROY STURROCK
A. Troy Sturrock
Vice President, Controller and Principal Accounting Officer
(Duly Authorized Officer)