Regency Energy Partners LP
Form 10-Q
May 09, 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 March 31, 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 170,104,818 common units outstanding as of May 2, 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
Bbls	Barrels
BTU	A unit of energy needed to raise the temperature of one pound of water by one degree Fahrenheit
ETC	Energy Transfer Company, the name assumed by La Grange Acquisition, L.P. for conducting business and shared services, a wholly owned subsidiary of ETP
ETE	Energy Transfer Equity, L.P.
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
LIBOR	London Interbank Offered Rate
Lone Star	Lone Star NGL LLC, a joint venture that is 30% owned by the Partnership and 70% owned by ETP
LTIP	Long-Term Incentive Plan
MEP	Midcontinent Express Pipeline LLC, a joint venture in which the Partnership currently owns a 50% interest
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, a joint venture that 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,” “will,” “plan,” “expec “continue,” “estimate,” “goal,” “forecast,” “may” or similar expressions help identify forward-looking statements. Although w 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 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 "Part II – Other Information - Item 1A. Risk Factors" in this Quarterly Report on Form 10-Q.

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)

	March 31, 2012	December 31, 2011
ASSETS		
Current Assets:		
Cash and cash equivalents	$66,306	$990
Trade accounts receivable, net of allowance of $864 and $1,190	43,169	43,917
Accrued revenues	99,730	68,011
Related party receivables	5,394	45,204
Derivative assets	5,671	4,374
Other current assets	25,320	24,628
Total current assets	245,590	187,124
Property, plant and equipment:		
Property, plant and equipment	2,142,111	2,080,932
Less accumulated depreciation	(237,159)	(195,404)
Property, plant and equipment, net	1,904,952	1,885,528
Other Assets:		
Investment in unconsolidated affiliates	2,007,414	1,924,705
Long-term derivative assets	324	474
Other, net of accumulated amortization of debt issuance costs of $12,057 and $10,186	38,011	39,353
Total other assets	2,045,749	1,964,532
Intangible assets, net of accumulated amortization of $52,174 and $44,856	733,565	740,883
Goodwill	789,789	789,789
TOTAL ASSETS	$5,719,645	$5,567,856
LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST		
Current Liabilities:		
Drafts payable	$—	$2,507
Trade accounts payable	50,340	73,462
Accrued cost of gas and liquids	76,375	84,943
Related party payables	25,235	12,625
Deferred revenues, including related party amounts of $28 and $41	13,728	16,225
Derivative liabilities	5,653	10,535
Other current liabilities	38,393	33,009
Total current liabilities	209,724	233,306
Long-term derivative liabilities	38,887	39,112
Other long-term liabilities	5,845	6,071
Long-term debt, net	1,604,915	1,687,147
Commitments and contingencies		
Series A Preferred Units, redemption amount of $84,889 and $84,773	72,196	71,144
Partners' capital and noncontrolling interest:		
Common units	3,421,707	3,173,090
General partner interest	329,064	329,876

Accumulated other comprehensive loss	(1,094)	(4,759)
Total partners' capital	3,749,677	3,498,207
Noncontrolling interest	38,401	32,869
Total partners' capital and noncontrolling interest	3,788,078	3,531,076
TOTAL LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST	$5,719,645	$5,567,856

See accompanying notes to condensed consolidated financial statements

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

	Three Months Ended March 31,	
	2012	2011
REVENUES		
Gas sales, including related party amounts of $5,480 and $1,262	$80,895	$110,087
NGL sales, including related party amounts of $22,289 and $72,993	159,279	118,251
Gathering, transportation and other fees, including related party amounts of $6,651 and $6,216	100,314	81,836
Net realized and unrealized loss from derivatives	(1,184)	(1,714)
Other, including related party amounts of $1,478 and $1,866	18,595	8,792
Total revenues	357,899	317,252
OPERATING COSTS AND EXPENSES		
Cost of sales, including related party amounts of $5,877 and $3,214	239,653	216,261
Operation and maintenance	40,981	33,672
General and administrative, including related party amounts of $4,300 and $3,905	15,695	18,997
Loss on asset sales, net	36	28
Depreciation and amortization	51,506	40,236
Total operating costs and expenses	347,871	309,194
OPERATING INCOME	10,028	8,058
Income from unconsolidated affiliates	31,958	23,808
Interest expense, net	(29,557)	(20,007)
Other income and deductions, net	16,522	2,414
INCOME BEFORE INCOME TAXES	28,951	14,273
Income tax expense (benefit)	51	(32)
NET INCOME	$28,900	$14,305
Net income attributable to noncontrolling interest	(399)	(231)
NET INCOME ATTRIBUTABLE TO REGENCY ENERGY PARTNERS LP	$28,501	$14,074
Amounts attributable to Series A Preferred Units	2,997	1,993
General partner's interest, including IDRs	2,488	1,292
Limited partners' interest in net income	$23,016	$10,789
Basic and diluted net income per common unit:		
Weighted average number of common units outstanding	158,690,035	137,304,783
Basic income per common unit	$0.15	$0.08
Diluted income per common unit	$0.14	$0.07
Distributions per common unit	$0.46	$0.445

See accompanying notes to condensed consolidated financial statements

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

	Three Months Ended March 31,	
	2012	2011
Net income	$28,900	$14,305
Other comprehensive income (loss):		
Net cash flow hedge amounts reclassified to earnings	3,665	3,429
Change in fair value of cash flow hedges	—	(16,996)
Total other comprehensive income (loss)	3,665	(13,567)
Comprehensive income	32,565	738
Comprehensive income attributable to noncontrolling interest	399	231
Comprehensive income attributable to Regency Energy Partners LP	$32,166	$507

See accompanying notes to condensed consolidated financial statements

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

	Three Months Ended March 31,	
	2012	2011
OPERATING ACTIVITIES:		
Net income	$28,900	$14,305
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization, including debt issuance cost, bond premium and excess fair value of unconsolidated affiliates amortization	54,491	43,111
Income from unconsolidated affiliates	(33,420)	(25,270)
Derivative valuation changes	(2,588)	(4,686)
Loss on asset sales, net	36	28
Unit-based compensation expenses	1,289	921
Cash flow changes in current assets and liabilities:		
Trade accounts receivable, accrued revenues and related party receivables	7,348	7,300
Other current assets	(723)	(2,096)
Trade accounts payable, accrued cost of gas and liquids, related party payables and deferred revenues	(33,546)	(12,145)
Other current liabilities	5,384	10,613
Distributions received from unconsolidated affiliates	29,012	25,270
Other assets and liabilities	(116)	15
Net cash flows provided by operating activities	56,067	57,366
INVESTING ACTIVITIES:		
Capital expenditures	(75,842)	(68,633)
Capital contributions to unconsolidated affiliates	(80,540)	—
Distribution in excess of earnings of unconsolidated affiliates	13,489	16,895
Proceeds from asset sales	13,058	6
Net cash flows used in investing activities	(129,835)	(51,732)
FINANCING ACTIVITIES:		
Net (repayments) borrowings under revolving credit facility	(82,000)	75,000
Debt issuance costs	(641)	(184)
Partner distributions	(76,139)	(63,599)
Disposition of assets between entities under common control in excess of historical cost	—	25
Contributions from noncontrolling interest	5,133	—
Bank overdraft	(2,507)	—

Issuance of common units under LTIP, net of forfeitures and tax withholding	(119)	393
Common unit offering, net of costs	297,302	—
Distributions to Series A Preferred Units	(1,945)	(1,945)
Net cash flows provided by financing activities	139,084	9,690
Net change in cash and cash equivalents	65,316	15,324
Cash and cash equivalents at beginning of period	990	9,400
Cash and cash equivalents at end of period	$66,306	$24,724
Non-cash Investing Activities:		
Accrued capital expenditures and contributions to unconsolidated affiliates	$36,080	$16,605

See accompanying notes to condensed consolidated financial statements

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	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	297,302	—	—	—	297,302
Issuance of common units under LTIP, net of forfeitures and tax withholding	9,296	(119)	—	—	—	(119)
Unit-based compensation expenses	—	1,289	—	—	—	1,289
Partner distributions	—	(72,891)	(3,248)	—	—	(76,139)
Accrued distributions to phantom units	—	(32)	—	—	—	(32)
Net income	—	26,013	2,488	—	399	28,900
Contributions from noncontrolling interest	—	—	—	—	5,133	5,133
Distributions to Series A Preferred Units	—	(1,911)	(34)	—	—	(1,945)
Accretion of Series A Preferred Units	—	(1,034)	(18)	—	—	(1,052)
Net cash flow hedge amounts reclassified to earnings	—	—	—	3,665	—	3,665
Balance - March 31, 2012	170,096,904	$3,421,707	$329,064	$ (1,094)	$ 38,401	$3,788,078

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 and its subsidiaries are 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 managing general partner of the Partnership and 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 inter-company items and transactions have been eliminated in consolidation. Certain information and footnote disclosures normally included in annual consolidated financial statements prepared in accordance with GAAP have been omitted pursuant to the rules and regulations of the SEC.

Use of Estimates. The unaudited condensed consolidated financial statements have been prepared in conformity with GAAP, 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. During the quarter ended March 31, 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 three months ended March 31, 2011, the year ended December 31, 2011 and the period from May 26, 2010 to December 31, 2010 was $1.1 million, $4.4 million and $2.5 million, respectively.

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

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 $297.3 million. The Partnership will use 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. The Partnership expects to complete this redemption in May 2012.

2. 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 months ended March 31, 2012 and 2011:

	Three Months Ended March 31,					
	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	$23,016	158,690,035	$0.15	$10,789	137,304,783	$0.08
Effect of Dilutive Securities:						
Common unit options	—	21,129		—	31,056	
Phantom units *	—	361,550		—	222,124	
Series A Preferred Units	—	—		(582)	4,584,192	
Diluted income per unit	$23,016	159,072,714	$0.14	$10,207	142,142,155	$0.07

* Amount assumes maximum conversion rate for market condition awards.

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

	Three Months Ended March 31, 2012
Series A Preferred Units	4,638,732

3. Investment in Unconsolidated Affiliates

As of March 31, 2012, the Partnership has a 49.99% general partner interest in HPC, 50% membership interest in MEP, 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 March 31, 2012 and December 31, 2011 is as follows:

	March 31, 2012	December 31, 2011
HPC	$675,734	$682,046
MEP	605,303	613,942
Lone Star	712,965	628,717
Ranch JV	13,412	—
	$2,007,414	$1,924,705

The following tables summarize the Partnership's investment activities in each of the unconsolidated affiliates for the three months ended March 31, 2012 and 2011:

	Three Months Ended March 31, 2012			
	HPC	MEP	Lone Star	Ranch JV
Contributions to unconsolidated affiliates	—	—	79,840	13,412
Distributions from unconsolidated affiliates	16,159	19,386	6,956	—
Share of unconsolidated affiliates' net income	11,309	10,747	11,364	—
Amortization of excess fair value of investment	(1,462)	—	—	—

	Three Months Ended March 31, 2011			
	HPC	MEP	Lone Star	Ranch JV
Contributions to unconsolidated affiliates	$—	$—	*	**
Distributions from unconsolidated affiliates	16,728	25,437	*	**
Share of unconsolidated affiliates' net income	15,075	10,195	*	**
Amortization of excess fair value of investment	(1,462)	—	*	**

* The Partnership acquired a 30% membership interest in Lone Star in May 2011.

** The Partnership acquired a 33.33% membership interest in Ranch JV December 2011.

The following tables present selected income statement data for each of the unconsolidated affiliates, on a 100% basis, for the three months ended March 31, 2012 and 2011:

	Three Months Ended March 31, 2012			
	HPC	MEP	Lone Star	Ranch JV
Total revenues	$41,816	$66,160	$166,995	$—
Operating income (loss)	22,969	34,389	38,554	(24)
Net income (loss)	22,622	21,494	37,881	(24)

	Three Months Ended March 31, 2011			
	HPC	MEP	Lone Star	Ranch JV
Total revenues	$48,649	$64,824	*	**
Operating income	30,327	33,265	*	**
Net income	30,156	20,410	*	**

*The Partnership acquired a 30% membership interest in Lone Star in May 2011.
**The Partnership acquired a 33.33% membership interest in Ranch JV December 2011.

4. Derivative Instruments

Policies. The Partnership established comprehensive risk management policies and procedures to monitor and manage the market risks associated with commodity prices, counterparty credit and interest rates. The General Partner is responsible for delegation of transaction authority levels, and the Audit and Risk 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 market forces of supply and demand. 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 that settle 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 March 31, 2012, the Partnership has $1.1 million in net hedging losses in accumulated other comprehensive loss which will be amortized to earnings over the next 2 years. Over the next 12 months, the Partnership will amortize $1.5 million in net hedging losses to income.

Interest Rate Risk. The Partnership is exposed to variable interest rate risk as a result of borrowings under its revolving credit facility. As of March 31, 2012, total borrowings under the revolving credit facility were $250 million. 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, and because the margin on any sale is generally a very small percentage of the total sales price, 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 guarantee from a parent company.

The Partnership is exposed to credit risk from its derivative contract 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 March 31, 2012 would be $6 million which would be reduced by $3.5 million due to the netting feature. The Partnership has elected to present assets and liabilities under master netting agreements gross on the condensed consolidated balance sheets.

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

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

	Assets	Liabilities

	March 31, 2012	December 31, 2011	March 31, 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	4,791	—	5,653	—
Ethane put options	880	309	—	—
Interest rate swap contracts	—	—	—	470
Long-term amounts				
Commodity contracts	324	—	334	—
Embedded derivatives in Series A Preferred Units	—	—	38,553	39,049
Total derivatives not designated as cash flow hedges	5,995	309	44,540	39,519
Total derivatives	$5,995	$4,848	$44,540	$49,647

The Partnership's statement of operations for the three months ended March 31, 2012 and 2011 were impacted by derivative instruments activities as follows:

		Three Months Ended March 31, 2012	2011
Derivatives in cash flow hedging relationships:		Change in Value Recognized in AOCI on Derivatives (Effective Portion)	
Commodity derivatives		$—	$(16,996)
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	$—	$(3,429)
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	$—	$88
Derivatives in cash flow hedging relationships:	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) Recognized in Income on Pre-Hedge Designation Fair Value	
Commodity derivatives	Revenues	$—	$1,627
Derivatives not designated in a hedging relationship:	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) Amortized from AOCI into Income	
Commodity derivatives	Revenues	$(3,665)	$—
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	$2,481	$—

Interest rate swap contracts	Interest expense, net	(12)	(259)
Embedded derivatives in Series A Preferred Units	Other income & deductions, net	496	2,575
		$2,965	$2,316

5. Long-term Debt

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

	March 31, 2012	December 31, 2011
Senior notes	$1,354,915	$1,355,147
Revolving loans	250,000	332,000
Total	1,604,915	1,687,147
Less: current portion	—	—
Long-term debt	$1,604,915	$1,687,147
Availability under revolving credit facility:		
Total credit facility limit	$900,000	$900,000
Revolving loans	(250,000)	(332,000)
Letters of credit	(11,500)	(19,000)
Total available	$638,500	$549,000

Scheduled maturities of long-term debt at March 31, 2012 are as follows:

Years Ending December 31,	Amount	
2012 (remainder)	$—	
2013	—	
2014	250,000	
2015	—	
2016	250,000	
Thereafter	1,100,000	*
Total	$1,600,000	

*Excludes unamortized premiums of $4.9 million as of March 31, 2012.

Revolving Credit Facility. The weighted average interest rate on the total amounts outstanding under the Partnership's revolving credit facility was 3.09% and 2.78% as of March 31, 2012 and 2011, respectively.

Senior Notes. In April 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 March 31, 2012, the Partnership was in compliance with all 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. Since the Partnership has no independent operations, the guarantees are fully unconditional and joint and several of its subsidiaries, except for a few minor subsidiaries, and the Partnership has not included condensed consolidated financial information of guarantors of the senior notes.

6. Commitments and Contingencies

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

Keyes Litigation. In August 2008, Keyes Helium Company, LLC (“Keyes”) filed suit against RGS, the Partnership, the General Partner and various other subsidiaries. Keyes entered into an output contract with the Partnership’s predecessor-in-interest in 1996 under which it purchased all of the helium produced at the Lakin, Kansas processing plant. In September 2004, the Partnership decided to shut down its Lakin plant and contract with a third party for the processing of volumes processed at Lakin; as a result, the Partnership no longer delivered any helium to Keyes. In its suit, Keyes alleges it is entitled to damages for the costs of covering its purchases of helium. On May 7, 2010, the jury rendered a verdict in favor of the Partnership. No damages were awarded to the Plaintiffs. Plaintiffs have appealed the verdict. The hearing on appeal took place on April 24, 2012. A decision is not expected for several months.

7. Series A Preferred Units

On September 2, 2009, the Partnership issued 4,371,586 Series A Preferred Units. As of March 31, 2012, the Series A Preferred Units were convertible to 4,638,732 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.

The following table provides a reconciliation of the beginning and ending balances of the Series A Preferred Units for the three months ended March 31, 2012:

	Units	Amount	
Outstanding at beginning of period	4,371,586	$71,144	
Accretion to redemption value	—	1,052	
Outstanding at end of period	4,371,586	$72,196	*

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

8. 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. Also, the Partnership, 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 $3.9 million for the three months ended March 31, 2012 and 2011, respectively.

In conjunction with distributions by the Partnership to the limited and general partner interests, ETE received cash distributions of $15.5 million and $14 million during the three months ended March 31, 2012 and 2011, respectively.

The Partnership's Gathering and Processing segment, in the ordinary course of business, 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 $0.8 million for the three months ended March 31, 2011.

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 of $13.8 million and $20.4 million were recorded to the General Partner during the three months ended March 31, 2012 and 2011, respectively, in the Partnership's financial statements as operating expenses or general and administrative expenses. For the three months ended March 31, 2012 and 2011, respective reimbursements of $8.3 million and $5.5 million to ETP were recorded 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. The related party general and administrative expenses reimbursed to the Partnership was $4.2 million for each of the three months ended March 31, 2012 and 2011, 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 it as cost of sales.

9. 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.
Joint Ventures. The Partnership owns investments in four joint ventures:
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;
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; and
a 33.33% membership interest in Ranch JV, which, upon completion of construction in 2012, will process natural gas delivered from the NGLs-rich Bone Spring and Avalon shale formations in west Texas.
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. The Partnership does not record segment margin 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.
Results for each period, together with amounts related to balance sheets for each segment, are shown below:

	Three Months Ended March 31,	
	2012	2011
External Revenues		
Gathering and Processing	$307,167	$265,972
Joint Ventures	—	—
Contract Compression	37,201	38,436
Contract Treating	9,135	8,433
Corporate and Others	4,396	4,411
Eliminations	—	—

Total	$357,899	$317,252
Intersegment Revenues		
Gathering and Processing	$—	$—
Joint Ventures	—	—
Contract Compression	4,129	6,553
Contract Treating	494	—
Corporate and Others	56	67
Eliminations	(4,679)	(6,620)
Total	$—	$—
Segment Margin		
Gathering and Processing	$71,335	$53,800
Joint Ventures	—	—
Contract Compression	38,986	41,440
Contract Treating	7,883	7,251
Corporate and Others	4,648	5,053
Eliminations	(4,606)	(6,553)
Total	$118,246	$100,991
Operation and Maintenance		
Gathering and Processing	$28,223	$22,942
Joint Ventures	—	—
Contract Compression	16,407	16,504
Contract Treating	844	734
Corporate and Others	113	45
Eliminations	(4,606)	(6,553)
Total	$40,981	$33,672

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

	Three Months Ended March 31,	
	2012	2011
Total segment margin	$118,246	$100,991
Operation and maintenance	(40,981)	(33,672)
General and administrative	(15,695)	(18,997)
Loss on asset sales, net	(36)	(28)
Depreciation and amortization	(51,506)	(40,236)
Income from unconsolidated affiliates	31,958	23,808
Interest expense, net	(29,557)	(20,007)
Other income and deductions, net	16,522 *	2,414
Income before income taxes	$28,951	$14,273

* Other income and deductions, net for the three months ended March 31, 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 assets reflected in the consolidated balance sheet for each segment:

	March 31, 2012	December 31, 2011
Gathering and Processing	$1,978,072	$1,959,697
Joint Ventures	2,007,414	1,924,705
Contract Compression	1,395,797	1,405,600
Contract Treating	211,593	215,172
Corporate and Others	126,769	62,682
Total	$5,719,645	$5,567,856

10. 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 $1.3 million and $0.9 million, is recorded in general and administrative expense for the three months ended March 31, 2012 and 2011, respectively.

Common Unit Options. There was no common unit option activity for the three months ended March 31, 2012. The aggregate intrinsic value and weighted average contractual term in years as of March 31, 2012 for the outstanding and exercisable common unit options was $0.5 million and 4.1 years, respectively. During the three months ended March 31, 2011, the Partnership received $0.5 million in proceeds from the exercise of unit options.

Phantom Units. All phantom units granted prior to November 2010 were in substance two grants composed of (1) service condition grants with graded vesting over three years and (2) market condition grants with cliff vesting based upon the Partnership's relative ranking in total unitholder return among 20 peer companies. Distributions related to these unvested phantom units will be accrued and paid upon vesting. All phantom units granted after November 2010 were service condition grants only with graded vesting over five years. Distributions related to these unvested phantom units will be paid concurrent with the Partnership's distribution for common units.

The following table presents phantom units activity for the three months ended March 31, 2012:

Phantom Units	Units		Weighted Average Grant Date Fair Value
Outstanding at beginning of period	1,086,393		$ 24.51
Service condition grants	4,000		26.24
Vested service condition	(13,039	)	20.65
Forfeited service condition	(15,950	)	24.81
Outstanding at end of period	1,061,404		24.56

The Partnership expects to recognize $19.1 million of compensation expense related to non-vested phantom units over a period of 4.1 years.

11. 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 March 31, 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	$4,677	$4,677	$ —	$ 3,907	$ 3,907	$ —
NGLs	394	394	—	94	94	—
Condensate	44	44	—	538	538	—
Ethane - Put Options	880	880	—	309	309	—
Total Assets	$5,995	$5,995	$ —	$ 4,848	$ 4,848	$ —
Liabilities:						
Interest Rate Derivatives	$—	$—	$ —	$ 470	$ 470	$ —

Commodity Derivatives:						
Natural Gas	—	—	—	—	—	—
NGLs	3,809	3,809	—	8,561	8,561	—
Condensate	2,178	2,178	—	1,567	1,567	—
Embedded Derivatives in Series A Preferred Units	38,553	—	38,553	39,049	—	39,049
Total Liabilities	$44,540	$5,987	$ 38,553	$ 49,647	$ 10,598	$ 39,049

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	March 31, 2012	
Credit Spread	6.89	%
Volatility	16.06	%

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 three months ended March 31, 2012. There were no transfers between the fair value hierarchy levels for the three months ended March 31, 2012.

	Embedded Derivatives in Series A Preferred Units	
Balance at December 31, 2011	$39,049	
Change in fair value	(496	)
Balance at March 31, 2012	$38,553	

The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to their short-term maturities. Long-term debt, other than the senior notes, is comprised of borrowings under which interest accrues under a floating interest rate structure. Accordingly, the carrying value approximates fair value. The following table presents the estimated fair value of senior notes, based on third party market value quotations (Level 1), as of March 31, 2012 and December 31, 2011:

Outstanding Senior Notes	March 31, 2012	December 31, 2011
$250 million senior notes due 2016	$275,313	$276,250
$600 million senior notes due 2018	634,128	643,500
$500 million senior notes due 2021	524,750	516,250

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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.
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 and selling or delivering the pipeline-quality natural gas and NGLs to various markets and pipeline systems.
- Joint Ventures. We own investments in four joint ventures:

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;
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; and
a 33.33% membership interest in Ranch JV, which, upon completion of construction in 2012, will process natural gas delivered from the NGLs-rich Bone Spring and Avalon shale formations in west Texas.

- 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 measurements to analyze our performance. We view these measures as important tools for evaluating the success of our operations and review these measurements on a monthly basis for consistency and trend analysis. These measures include volumes, segment margin, total segment margin, adjusted segment margin, adjusted total segment margin and operation and maintenance expense on a segment and company-wide basis and EBITDA and adjusted EBITDA on a company-wide basis.
Volumes. We must continually obtain new supplies of natural gas to maintain or increase throughput volumes on our gathering and processing systems. Our ability to maintain existing supplies of natural gas and obtain new supplies is affected by (i) the level of workovers or recompletions of existing connected wells and successful drilling activity in areas currently dedicated to our gathering and processing systems, (ii) our ability to compete for volumes from successful new wells in other areas and (iii) our ability to obtain natural gas that has been released from other commitments. We routinely monitor producer activity in the areas served by our gathering and processing systems to pursue new supply opportunities.
Segment Margin and Total Segment Margin. We define segment margin, generally, as revenues minus cost of sales. We calculate our Gathering and Processing segment margin and Corporate and Others segment margin as our revenues generated from operations less the cost of natural gas and NGLs purchased and other cost of sales, including

third-party transportation and processing fees.

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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;
- loss (gain) on asset sales, net;
- loss on debt refinancing;
- 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.

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.

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Neither EBITDA nor adjusted EBITDA should be considered as an alternative to, or more meaningful than, net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP. EBITDA is the starting point in determining cash available for distribution, which is an important non-GAAP financial measure for a publicly traded partnership.

The following table presents a reconciliation of EBITDA and adjusted EBITDA to net cash flows provided by operating activities and to net income (loss) for the Partnership:

	Three Months Ended March 31,	
Reconciliation of "Adjusted EBITDA" to net cash flows provided by operating activities and net income	2012	2011
Net cash flows provided by operating activities	$56,067	$57,366
Add (deduct):		
Depreciation and amortization, including debt issuance cost, bond premium and excess fair value of unconsolidated affiliates amortization	(54,491)	(43,111)
Income from unconsolidated affiliates	33,420	25,270
Derivative valuation change	2,588	4,686
Loss on asset sales, net	(36)	(28)
Unit-based compensation expenses	(1,289)	(921)
Trade accounts receivable, accrued revenues and related party receivables	(7,348)	(7,300)
Other current assets	723	2,096
Trade accounts payable, accrued cost of gas and liquids, related party payables and deferred revenues	33,546	12,145
Other current liabilities	(5,384)	(10,613)
Distributions received from unconsolidated affiliates	(29,012)	(25,270)
Other assets and liabilities	116	(15)
Net income	28,900	14,305
Add (deduct):		
Interest expense, net	29,557	20,007
Depreciation and amortization expense	51,506	40,236
Income tax expense (benefit)	51	(32)
EBITDA	110,014	74,516
Add (deduct):		
Non-cash gain from commodity and embedded derivatives	(2,115)	(4,290)
Unit-based compensation expenses	1,289	921
Loss on asset sales, net	36	28
Income from unconsolidated affiliates	(31,958)	(23,808)
Partnership's interest in unconsolidated affiliates' adjusted EBITDA	57,218	44,459
Other income, net	(434)	(89)
Adjusted EBITDA	$134,050	$91,737

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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 three months ended March 31, 2012 and 2011:

	Three Months Ended March 31, 2012				
	HPC	MEP	Lone Star	Ranch JV	Total
Net income (loss)	$22,622	$21,494	$37,881	$(24)	
Add:					
Depreciation and amortization	9,094	17,364	12,270	—	
Interest expense, net	480	12,894	—	—	
Other expenses	—	—	673	—	
Adjusted EBITDA	32,196	51,752	50,824	(24)	
Ownership interest	49.99 %	50 %	30 %	33.33 %	
Partnership's interest in adjusted EBITDA	$16,095	$25,876	$15,247	$—	$57,218

	Three Months Ended March 31, 2011				
	HPC	MEP	Lone Star	Ranch JV	Total
Net income	$30,156	$20,410	N/A	N/A	
Add:					
Depreciation and amortization	8,082	17,377	N/A	N/A	
Interest expense, net	136	12,855	N/A	N/A	
Other expenses	11	—	N/A	N/A	
Adjusted EBITDA	38,385	50,642	N/A	N/A	
Ownership interest	49.99 %	49.9 %	N/A	N/A	
Partnership's interest in adjusted EBITDA	$19,189	$25,270	$—	$—	$44,459

N/A We acquired a 30% membership interest in Lone Star in May 2011. 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 month periods ended March 31, 2012 and 2011 for the Partnership:

	Three Months Ended March 31,	
	2012	2011
Net income	$28,900	$14,305
Add (deduct):		
Operation and maintenance	40,981	33,672
General and administrative	15,695	18,997
Loss on asset sales, net	36	28
Depreciation and amortization	51,506	40,236
Income from unconsolidated affiliates	(31,958)	(23,808)
Interest expense, net	29,557	20,007
Other income and deductions, net	(16,522)	(2,414)
Income tax expense (benefit)	51	(32)
Total segment margin	118,246	100,991
Add:		
Non-cash gain from commodity derivatives	(1,619)	(1,715)
Adjusted total segment margin	$116,627	$99,276

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Three Months Ended March 31, 2012 vs. Three Months Ended March 31, 2011

	Three Months Ended March 31,			
	2012	2011	Change	Percent
Total revenues	$357,899	$317,252	$40,647	13 %
Cost of sales	239,653	216,261	(23,392)	11
Total segment margin [1]	118,246	100,991	17,255	17
Operation and maintenance	40,981	33,672	(7,309)	22
General and administrative	15,695	18,997	3,302	17
Loss on asset sales, net	36	28	(8)	29
Depreciation and amortization	51,506	40,236	(11,270)	28
Operating income	10,028	8,058	1,970	24
Income from unconsolidated affiliates	31,958	23,808	8,150	34
Interest expense, net	(29,557)	(20,007)	(9,550)	48
Other income and deductions, net	16,522	2,414	14,108	584
Income before income taxes	28,951	14,273	14,678	103
Income tax expense (benefit)	51	(32)	(83)	259
Net income	28,900	14,305	14,595	102
Net income attributable to noncontrolling interest	(399)	(231)	(168)	73
Net income attributable to Regency Energy Partners LP	$28,501	$14,074	$14,427	103
Gathering and processing segment margin	$71,335	$53,800	$17,535	33
Non-cash gain from commodity derivatives	(1,619)	(1,715)	96	6
Adjusted gathering and processing segment margin	69,716	52,085	17,631	34
Contract compression segment margin [2]	38,986	41,440	(2,454)	6
Contract treating segment margin [2]	7,883	7,251	632	9
Corporate and others segment margin	4,648	5,053	(405)	8
Intersegment eliminations [2]	(4,606)	(6,553)	1,947	30
Adjusted total segment margin	$116,627	$99,276	$17,351	17 %

(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 $4.6 million and $6.6 million for the three months ended March 31, 2012 and 2011, respectively. These intersegment revenues were eliminated upon consolidation.

Net Income Attributable to Regency Energy Partners LP. Our income increased to $28.5 million for the three months ended March 31, 2012 from $14.1 million for the three months ended March 31, 2011. The major components of this change were as follows:

- $17.3 million increase in total segment margin primarily due to a $17.5 million increase in Gathering and Processing segment margin related to additional volumes in south and west Texas and in north Louisiana;
- $14.1 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;
- $8.2 million increase in income from unconsolidated affiliates primarily due to our acquisition of a 30% interest in Lone Star in May 2011;
- $3.3 million decrease in general and administrative expenses primarily due to decreases in employee related costs, office expenses, and legal fees; offset by
- $11.3 million increase in depreciation and amortization expense primarily related to the completion of various organic growth projects since March 2011 as well as an out of period adjustment of $6.9 million;

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- $9.6 million increase in interest expense primarily related to the interest associated with the $500 million senior notes we issued in May 2011; and
- $7.3 million increase in operation and maintenance expense primarily due to increases in compressor maintenance costs, employee expenses, plant operating expenses and consumable products.

Adjusted Total Segment Margin. Adjusted total segment margin increased to $116.6 million in the three months ended March 31, 2012 from $99.3 million in the three months ended March 31, 2011. The major components of this change were as follows:

- Adjusted Gathering and Processing segment margin increased to $69.7 million during the three months ended March 31, 2012 from $52.1 million for the three months ended March 31, 2011 primarily due to volume growth in south and west Texas and in north Louisiana. Total Gathering and Processing throughput increased to 1,387,000 MMBtu/d during the three months ended March 31, 2012 from 1,006,000 MMBtu/d during the three months ended March 31, 2011. Total NGL gross production increased to 38,000 Bbls/d during the three months ended March 31, 2012 from 28,000 Bbls/d during the three months ended March 31, 2011;
- Contract Compression segment margin decreased to $39 million in the three months ended March 31, 2012 from $41.4 million in the three months ended March 31, 2011, which was primarily due to the decrease in intersegment transactions with the Gathering and Processing segment as a result of the transfer of certain compression units from the Contract Compression segment to the Gathering and Processing segment in the second quarter of 2011. The decrease was also due to a slight decrease in revenue generating horsepower from external customers. As of March 31, 2012, our Contract Compression segment's total revenue generating horsepower was 761,000 compared to 762,000 as of March 31, 2011;
- Contract Treating segment margin increased to $7.9 million for the three months ended March 31, 2012 from $7.3 million for the three months ended March 31, 2011. Revenue generating GPM as of March 31, 2012 and March 31, 2011 was 3,370 and 3,268, respectively; and
- Intersegment eliminations decreased to $4.6 million in the three months ended March 31, 2012 from $6.6 million in the three months ended March 31, 2011. The decrease was primarily due to a decrease in transactions between the Gathering and Processing and the Contract Compression segments as a result of the transfer of certain compression units from the Contract Compression segment to the Gathering and Processing segment in the second quarter of 2011.

Operation and Maintenance. Operation and maintenance expense increased to $41 million in the three months ended March 31, 2012 from $33.7 million during the three months ended March 31, 2011. The change was primarily due to the following:

- $3.2 million increase in compressor maintenance expense primarily due to an increase in chemical products, lube oil and materials costs;
- $1.8 million increase in employee expenses primarily due to organic growth projects in south and west Texas;
- $1.3 million increase in plant operating expenses primarily related to increased activity in south Texas; and
- $0.8 million increase in ad valorem taxes.

General and Administrative. General and administrative expense decreased to $15.7 million in the three months ended March 31, 2012 from $19 million during the three months ended March 31, 2011. The change was primarily due to the following:

- $1.3 million decrease in employee related costs due to the shared services integration and subsequent reduction in employee headcount; and
- $1.9 million decrease in office expenses primarily related to a decrease in office expense and legal fees.

Depreciation and Amortization. Depreciation and amortization expense increased to $51.5 million in the three months ended March 31, 2012 from $40.2 million in the three months ended March 31, 2011. This increase was the result of $4.4 million of additional depreciation and amortization expense due to the completion of various organic growth projects since April 2011 and $6.9 million related to an "out-of-period" adjustment for all periods subsequent to May 26, 2010 (the "Successor" period 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 quarters ended March 31, 2012 and 2011 would have been $44.6 million and $41.3 million, respectively.

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Income from Unconsolidated Affiliates. Income from unconsolidated affiliates increased to $32 million for the three months ended March 31, 2012 from $23.8 million for the three months ended March 31, 2011. The schedule below summarizes the components of income from unconsolidated affiliates and our ownership interest for the three months ended March 31, 2012 and 2011, respectively:

	Three Months Ended March 31, 2012				
	HPC	MEP	Lone Star	Ranch JV	Total
Net income (loss)	$22,622	$21,494	$37,881	$(24)	$81,973
Ownership interest	49.99 %	50 %	30 %	33.33 %	N/M
Share of unconsolidated affiliates' net income	11,309	10,747	11,364	—	33,420
Less: Amortization of excess fair value of unconsolidated affiliates	(1,462)	—	—	—	(1,462)
Income from unconsolidated affiliates	$9,847	$10,747	$11,364	$—	$31,958
	Three Months Ended March 31, 2011				
	HPC	MEP	Lone Star	Ranch JV	Total
Net income	$30,156	$20,410	N/A	N/A	$50,566
Ownership interest	49.99 %	49.9 %	N/A	N/A	N/M
Share of unconsolidated affiliates' net income	15,075	10,195	N/A	N/A	25,270
Less: Amortization of excess fair value of unconsolidated affiliates	(1,462)	—	N/A	N/A	(1,462)
Income from unconsolidated affiliates	$13,613	$10,195	N/A	N/A	$23,808

N/A We acquired a 30% membership interest in Lone Star in May 2011 and a 33.33% membership interest in Ranch JV in December 2011.
N/M Not meaningful.

HPC's net income decreased to $22.6 million for the three months ended March 31, 2012 from $30.2 million for the three months ended March 31, 2011, primarily due to expiration of certain contracts not renewed as well as lower throughput from one customer, whose system has been shut down since June 2011. MEP's net income increased to $21.5 million for the three months ended March 31, 2012 from $20.4 million for the three months ended March 31, 2011, primarily due to an increase in throughput.

The following table presents operational data for each of our unconsolidated affiliates for the three months ended March 31, 2012 and 2011:

		Three Months Ended March 31,	
	Operational data	2012	2011
HPC	Throughput (MMBtu/d)	941,139	1,516,632
MEP	Throughput (MMBtu/d)	1,429,103	1,219,717
Lone Star	West Texas Pipeline – Throughput (Bbls/d)	134,616	N/A
	NGL Fractionation Throughput (Bbls/d)	19,245	N/A
Ranch JV		*	N/A

*Ranch JV has not begun operations.
N/A We acquired a 30% membership interest in Lone Star in May 2011 and a 33.33% membership interest in Ranch JV in December 2011.

Interest Expense, Net. Interest expense, net increased to $29.6 million for the three months ended March 31, 2012 from $20 million for the three months ended March 31, 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 $16.5 million in the three months ended March 31, 2012 from $2.4 million in the three months ended March 31, 2011, primarily due to a $15.6 million one-time producer payment received in March 2012 related to an assignment of certain contracts.

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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 6 – Commitments and Contingencies to the condensed consolidated financial statements included in Item 1 of this report.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

We expect our sources of liquidity to include:

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

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**	$275
Contract Compression segment	70
Contract Treating segment	40
Joint Ventures segment: *	
Lone Star**	350 - 400
Ranch JV	35
Corporate and Others segment	5
Total	$ 775 - 825
Maintenance Capital Expenditures; including our proportionate share related to our joint ventures	$30

* Our capital expenditures in the Joint Ventures segment represent capital contributions to those joint ventures to fund their growth projects.

** In addition to the 2012 capital expenditures disclosed above, we expect to spend $150 million in our Gathering and Processing segment beyond 2012, which represents the continuing capital expenditures on our approved growth projects; and $100 million in our Joint Venture segment beyond 2012, which represents our portion of the capital contributions to Lone Star to fund its approved growth projects.

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 permanently finance them. Our working capital is also influenced by current derivative assets and liabilities due to fair value changes in our derivative positions being reflected on our balance sheet. These derivative assets and liabilities represent our expectations for the settlement of derivative rights and obligations over the next 12 months, and should be viewed differently from trade accounts receivable and accounts payable, which settle over

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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.

We had a working capital surplus of $35.9 million at March 31, 2012 compared to a working capital deficit of $46.2 million at December 31, 2011. This surplus was primarily due to a $65.3 million increase in cash and cash equivalents and a decrease in net trade accounts receivables and accounts payables of $22.4 million due to the timing of cash receipts and disbursements.

Cash Flows from Operating Activities. Net cash flows provided by operating activities slightly decreased to $56.1 million in the three months ended March 31, 2012 from $57.4 million in the three months ended March 31, 2011.

Cash Flows used in Investing Activities. Net cash flows used in investing activities increased to $129.8 million in the three months ended March 31, 2012 from $51.7 million in the three months ended March 31, 2011, primarily as a result of capital contributions we made to unconsolidated affiliates for the growth projects described below.

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 three months ended March 31, 2012, we incurred $138 million of growth capital expenditures. Growth capital expenditures for the three months ended March 31, 2012 were primarily related to $39 million for organic growth projects for our Gathering and Processing segment, $19 million for the fabrication of new compressor packages for our Contract Compression segment, $71 million for growth projects for our Joint Ventures segment, and $9 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 three months ended March 31, 2012, we incurred $7 million of maintenance capital expenditures.

Cash Flows from Financing Activities. Net cash flows provided by financing activities increased to $139.1 million in the three months ended March 31, 2012 from $9.7 million during the same period in 2011. The increase is primarily due to our issuing common units resulting in net proceeds of $297.3 million in March 2012. These cash flows were partially offset by repayments under our revolving credit facility and increased Partnership distributions.

Capital Resources.

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 $297.3 million. We will use 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. We expect to complete this redemption in May 2012.

Senior Notes Redemption. As described above, in April 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.

Cash Distributions from Unconsolidated Affiliates. The following table summarizes the cash distributions from unconsolidated affiliates for the three months ended March 31, 2012 and 2011:

	Three Months Ended March 31,		
	2012	2011	
HPC	$16,159	$16,728	
MEP	19,386	25,437	*
Lone Star	6,956	—	**
	$42,501	$42,165	

* The decrease in MEP distributions is primary due to a change in its monthly distribution practice made in January 2011 whereby distributions are now paid concurrently as opposed to a month lag.

** We acquired a 30% membership interest in Lone Star in May 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 market forces of supply and demand. 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 March 31, 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)	
April 2012-September 2012	Ethane	140	(MBbls)	Index	0.47	($/gallon)	$(226)	$295
July 2012-December 2012	Ethane- Put Option	110	(MBbls)	Index	0.66	($/gallon)	880	185
April 2012-March 2013	Propane	252	(MBbls)	Index	1.2	($/gallon)	(658)	1,335
April 2012-September 2013	Normal Butane	219	(MBbls)	Index	1.69	($/gallon)	(1,659)	1,731
April 2012-March 2013	Natural Gasoline	76	(MBbls)	Index	2.11	($/gallon)	(872)	761
April 2012-December 2014	West Texas Intermediate Crude	401	(MBbls)	Index	97.86	($/Bbl)	(2,134)	4,144
April 2012-December 2013	Natural Gas	2,838,000	(MMBtu)	Index	4.54	($/MMBtu)	4,677	821
					Total Fair Value		$8	

* 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 March 31, 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 March 31, 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 6, Commitments and Contingencies, included in the notes to the unaudited condensed consolidated financial statements included under Part I, Item 1, which information is incorporated by reference into this item.

Item 1A. Risk Factors

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

RISKS RELATED TO OUR BUSINESS

Increased regulation of hydraulic fracturing could result in reductions or delays in drilling and completing new oil and natural gas wells, which could adversely impact our revenues by decreasing the volumes of natural gas that we gather, process and transport.

Certain of our customers' natural gas is developed from formations requiring hydraulic fracturing as part of the completion process. Fracturing is a process where water, sand, and chemicals are injected under pressure into subsurface formations to stimulate production. While the underground injection of fluids is regulated by the U.S. EPA under the Safe Drinking Water Act (“SWDA”), fracturing is excluded from regulation unless the injection fluid is diesel fuel. Congress has recently considered legislation that would repeal the exclusion, allowing EPA to more generally regulate fracturing, and requiring disclosure of chemicals used in the fracturing process. If enacted, such legislation could require fracturing to meet permitting and financial responsibility, siting and technical specifications relating to well construction, plugging and abandonment. EPA is also considering various regulatory programs directed at hydraulic fracturing. For example, on October 21, 2011, the EPA announced its intention to propose regulations by 2014 under the federal Clean Water Act to further regulate wastewater discharges from hydraulic fracturing and other natural gas production. In November 2011, EPA indicated it may initiate rulemaking under the Toxic Substances Control Act to obtain data regarding the composition of hydraulic fracturing fluids. The adoption of new federal laws or regulations imposing reporting obligations on, or otherwise limiting or regulating, the hydraulic fracturing process could make it more difficult to complete oil and natural gas wells in shale formations, increase our and our customers' costs of compliance, and adversely affect the hydraulic fracturing services that we render for our E&P customers. In addition, the U.S. EPA is currently studying the potential adverse impact that each stage of hydraulic fracturing may have on the environment. Results of the study are expected between later in 2012 and 2014. Several states in which our customers operate have also adopted regulations requiring disclosure of fracturing fluid components or otherwise regulate their use more closely.

On April 17, 2012 EPA approved final rules establishing new air emission standards for oil and natural gas production and natural gas processing operations. This rulemaking addresses emissions of various pollutants frequently associated with oil and natural gas production and processing activities. For new or reworked hydraulically-fractured wells, the final rule requires controlling emissions through flaring until 2015, when the rule requires the use of reduced emission (or “green”) completions, meaning equipment must be installed to separate gas and liquid hydrocarbons at the well head, enabling gas capture. The rule also establishes

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specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks gas processing plants and certain other equipment. These rules may require a number of modifications to our and our customers' operations, including the installation of new equipment to control emissions. Compliance with these rules could result in additional costs, including increased capital expenditures and operating costs, for us and our customers which may adversely impact our business.

Additional federal or state legislation or regulation of hydraulic fracturing or related activities could result in operational delays, increased operating costs, and additional regulatory burdens on exploration and production operators, as well as aspects of our business. This could reduce production of natural gas and, in turn, adversely affect our revenues and results of operations by decreasing the volumes of natural gas and NGLs that we gather, process and transport.

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.

Item 6. Exhibits

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

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: May 9, 2012

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