Regency Energy Partners LP
Form 10-Q
May 09, 2013
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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, 2013
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 202,345,448 common units outstanding as of May 3, 2013.

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Regency Energy Partners LP

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Introductory Statement

References in this report to the "Partnership," "we," "our," "us" and similar terms 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
ELG	Edwards Lime Gathering LLC and its wholly-owned subsidiaries, ELG Oil LLC and ELG Utility LLC
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 Partnership through Regency Employees Management LLC
Gulf States	Gulf States Transmission LLC, a wholly-owned subsidiary of the Partnership
Holdco	ETP Holdco Corporation
HPC	RIGS Haynesville Partnership Co., a general partnership, and its wholly-owned subsidiary, Regency Intrastate Gas LP
IDRs	Incentive Distribution Rights
Lone Star	Lone Star NGL LLC
LTIP	Long-Term Incentive Plan
MBbls	One thousand barrels
MEP	Midcontinent Express Pipeline LLC
MMBtu	One million BTUs
NGLs	Natural gas liquids, including ethane, propane, normal butane, iso butane and natural gasoline
NYMEX	New York Mercantile Exchange
Partnership	Regency Energy Partners LP
PEPL Holdings	PEPL Holdings, LLC, a wholly-owned subsidiary of Southern Union
Ranch JV	Ranch Westex JV LLC
Regency Western	Regency Western G&P LLC, an indirectly wholly owned subsidiary of the Partnership
RGS	Regency Gas Services LP, a wholly-owned subsidiary of the Partnership
RIGS	Regency Intrastate Gas System
SEC	Securities and Exchange Commission
Senior Notes	The collective of 2016 Notes, 2018 Notes, 2021 Notes, 2023 5.5% Notes and 2023 4.5% Notes
Series A Preferred Units	Series A convertible redeemable preferred units
Services Co.	ETE Services Company, LLC
Southern Union	Southern Union Company
SUGS	Southern Union Gathering Company LLC

WTI	West Texas Intermediate Crude

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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, condensate 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 our contract services business;
- the level of creditworthiness of, and performance by, our counterparties and customers;
- our access to capital to fund organic growth projects and acquisitions, and our ability to obtain debt or equity financing on satisfactory terms;
- our use of derivative financial instruments to hedge commodity and interest rate risks;
- the amount of collateral required to be posted from time-to-time in our transactions;
- changes in commodity prices, interest rates and demand for our services;
- changes in laws and regulations impacting the midstream sector of the natural gas industry, including those that relate to climate change and environmental protection and safety;
- weather and other natural phenomena;
- industry changes including the impact of consolidations and changes in competition;
- regulation of transportation rates on our natural gas and NGL pipelines;
- our ability to obtain indemnification related to cleanup liabilities and to clean up any hazardous materials release on satisfactory terms;
- our ability to obtain required approvals for construction or modernization of our facilities and the timing of production from such facilities; and
- the effect of accounting pronouncements issued periodically by accounting standard setting boards.

If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may differ materially from those anticipated, estimated, projected or expected.

Other factors that could cause our actual results to differ from our projected results are discussed in Item 1A of our December 31, 2012 Annual Report on Form 10-K.

Each forward-looking statement speaks only as of the date of the particular statement and we undertake no obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

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PART I – FINANCIAL INFORMATION
Item 1. Financial Statements
Regency Energy Partners LP
Condensed Consolidated Balance Sheets
(in millions)
(unaudited)

	March 31, 2013	December 31, 2012
ASSETS		
Current Assets:		
Cash and cash equivalents	$44	$53
Trade accounts receivable, net of allowance of $1 and $1	38	40
Accrued revenues	112	107
Related party receivables	2	4
Derivative assets	2	4
Other current assets	30	29
Total current assets	228	237
Property, plant and equipment:		
Property, plant and equipment	2,678	2,517
Less accumulated depreciation	(393)	(355)
Property, plant and equipment, net	2,285	2,162
Other Assets:		
Investment in unconsolidated affiliates	2,226	2,214
Long-term derivative assets	1	1
Other, net of accumulated amortization of debt issuance costs of $20 and $17	39	41
Total other assets	2,266	2,256
Intangible assets, net of accumulated amortization of $82 and $74	704	712
Goodwill	790	790
TOTAL ASSETS	$6,273	$6,157
LIABILITIES AND PARTNERS’ CAPITAL AND NONCONTROLLING INTEREST		
Current Liabilities:		
Drafts payable	$7	$6
Trade accounts payable	97	102
Accrued cost of gas and liquids	84	83
Related party payables	24	37
Deferred revenues	18	17
Derivative liabilities	3	1
Other current liabilities	56	41
Total current liabilities	289	287
Long-term derivative liabilities	39	25
Other long-term liabilities	3	5
Long-term debt, net	2,336	2,157
Commitments and contingencies		
Series A Preferred Units, redemption amount of $85 and $85	73	73
Partners’ capital and noncontrolling interest:		
Common units	3,121	3,207
General partner interest	324	326
Total partners’ capital	3,445	3,533

Noncontrolling interest	88	77
Total partners' capital and noncontrolling interest	3,533	3,610
TOTAL LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST	$6,273	$6,157

See accompanying notes to condensed consolidated financial statements

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

	Three Months Ended March 31,	
	2013	2012
REVENUES		
Gas sales, including related party amounts of $8 and $5	$104	$81
NGL sales, including related party amounts of $1 and $22	126	159
Gathering, transportation and other fees, including related party amounts of $8 and $7	109	100
Net realized and unrealized loss from derivatives	(3)	(1)
Other, including related party amounts of $0 and $1	13	19
Total revenues	349	358
OPERATING COSTS AND EXPENSES		
Cost of sales, including related party amounts of $4 and $6	229	240
Operation and maintenance	45	41
General and administrative, including related party amounts of $4 and $4	17	16
Loss on asset sales, net	1	—
Depreciation and amortization	48	51
Total operating costs and expenses	340	348
OPERATING INCOME	9	10
Income from unconsolidated affiliates	35	32
Interest expense, net	(37)	(30)
Other income and deductions, net	(14)	17
(LOSS) INCOME BEFORE INCOME TAXES	(7)	29
Income tax benefit	(2)	—
NET (LOSS) INCOME	$(5)	$29
Net income attributable to noncontrolling interest	—	—
NET (LOSS) INCOME ATTRIBUTABLE TO REGENCY ENERGY PARTNERS LP	$(5)	$29
Amounts attributable to Series A Preferred Units	2	3
General partner's interest, including IDRs	2	3
Limited partners' interest in net (loss) income	$(9)	$23
Basic and diluted net (loss) income per common unit:		
Weighted average number of common units outstanding	170,952,804	158,690,035
Basic (loss) income per common unit	$(0.06)	$0.15
Diluted (loss) income per common unit	$(0.06)	$0.14
Distributions per common unit	$0.46	$0.46

See accompanying notes to condensed consolidated financial statements

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

	Three Months Ended March 31,	
	2013	2012
Net (loss) income	$(5)	$29
Other comprehensive income:		
Net cash flow hedge amounts reclassified to earnings	—	3
Total other comprehensive income	—	3
Comprehensive (loss) income	(5)	32
Comprehensive income attributable to noncontrolling interest	—	—
Comprehensive (loss) income attributable to Regency Energy Partners LP	$(5)	$32

See accompanying notes to condensed consolidated financial statements

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

	Three Months Ended March 31,	
	2013	2012
OPERATING ACTIVITIES:		
Net (loss) income	$(5)	$29
Reconciliation of net income (loss) to net cash flows provided by operating activities:		
Depreciation and amortization, including debt issuance cost amortization and bond premium amortization	50	54
Income from unconsolidated affiliates	(35)	(32)
Derivative valuation changes	18	(3)
Loss on asset sales, net	1	—
Unit-based compensation expenses	2	1
Cash flow changes in current assets and liabilities:		
Trade accounts receivable, accrued revenues and related party receivables	(8)	7
Other current assets and other current liabilities	13	5
Trade accounts payable, accrued cost of gas and liquids, related party payables and deferred revenues	(4)	(34)
Distributions of earnings received from unconsolidated affiliates	36	29
Cash flow changes in other assets and liabilities	(1)	—
Net cash flows provided by operating activities	67	56
INVESTING ACTIVITIES:		
Capital expenditures	(167)	(76)
Capital contributions to unconsolidated affiliates	(43)	(80)
Distributions in excess of earnings of unconsolidated affiliates	16	13
Proceeds from asset sales	12	13
Net cash flows used in investing activities	(182)	(130)
FINANCING ACTIVITIES:		
Net borrowings (repayments) under revolving credit facility	179	(82)
Debt issuance costs	—	(1)
Partner distributions	(83)	(76)
Contributions from noncontrolling interest	11	5
Draft payables	1	(2)
Common unit offering, net of issuance costs	—	297
Distributions to Series A Preferred Units	(2)	(2)
Net cash flows provided by financing activities	106	139
Net change in cash and cash equivalents	(9)	65
Cash and cash equivalents at beginning of period	53	1
Cash and cash equivalents at end of period	$44	$66
Supplemental cash flow information:		
Non-cash capital expenditures	$62	$23
Non-cash capital contributions to unconsolidated affiliates	8	13

See accompanying notes to condensed consolidated financial statements

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Regency Energy Partners LP
Condensed Consolidated Statement of Partners' Capital and Noncontrolling Interest
(in millions except unit data)
(unaudited)

	Regency Energy Partners LP Units				
	Common	Common Unitholders	General Partner Interest	Noncontrolling Interest	Total
Balance - December 31, 2012	170,951,457	$3,207	$326	$ 77	$3,610
Issuance of common units under LTIP, net of forfeitures and tax withholding	8,975	—	—	—	—
Unit-based compensation expenses	—	2	—	—	2
Partner distributions	—	(79)	(4)	—	(83)
Net (loss) income	—	(7)	2	—	(5)
Contributions from noncontrolling interest	—	—	—	11	11
Distributions to Series A Preferred Units	—	(2)	—	—	(2)
Balance - March 31, 2013	170,960,432	$3,121	$324	$ 88	$3,533

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 millions)
(unaudited)

1. Organization and Summary of Significant Accounting Policies

Organization. The unaudited condensed consolidated financial statements presented herein contain the results of Regency Energy Partners LP and its subsidiaries (the "Partnership"), a Delaware limited partnership. The Partnership and its subsidiaries are engaged in the business of gathering and processing, 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, 2012. 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.

Quarterly Distributions of Available Cash. Following are distributions declared by the Partnership subsequent to December 31, 2012:

Quarter Ended	Record Date	Payment Date	Cash Distributions (per common unit)
December 31, 2012	February 7, 2013	February 14, 2013	$0.46
March 31, 2013	May 6, 2013	May 13, 2013	$0.46

SUGS Acquisition. On April 30, 2013, the Partnership and Regency Western acquired SUGS from Southern Union, a wholly owned subsidiary of Holdco, for approximately $1.5 billion (the "SUGS Acquisition"). The Partnership financed the acquisition by issuing to Holdco 31 million Partnership common units and 6 million recently created Class F common units. The Class F common units are not entitled to participate in the Partnership's distributions for twenty-four months post-transaction closing. The remaining $600 million, less $107 million of estimated closing adjustments, was paid in cash. In addition, in conjunction with the acquisition, ETE has agreed to forgo IDR payments on the Partnership common units issued with this transaction for the twenty-four months post-transaction closing and to eliminate the $10 million annual management fee paid by the Partnership for two years post-transaction close.

The common units and Class F common units related to the SUGS Acquisition were issued in a private placement conducted in accordance with the exemption from registration requirements of the Securities Act of 1933, as amended under Section 4(e) thereof. The Class F common units will convert into common units on a one-for-one basis in May 2015.

The cash portion of the SUGS Acquisition was funded from the proceeds of senior notes issued by the Partnership on April 30, 2013 in a private placement. PEPL Holdings provided a guarantee of collection with respect to the payment of the principal amounts of the senior notes issued by the Partnership.

Because the SUGS Acquisition is a transaction between commonly controlled entities (i.e., the buyer and the sellers are each affiliates of ETE), the Partnership will be required to account for the acquisition in a manner similar to the pooling of interest method of accounting. Under this method of accounting, the Partnership will reflect historical balance sheet data for both the Partnership and SUGS instead of reflecting the fair market value of SUGS assets and liabilities. The Partnership will retrospectively adjust its financial statements to include the operations of SUGS from

March 26, 2012 (the date upon which common control began), beginning with the first issuance of financial statements for periods including the consummation of the transaction.

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2. (Loss) Income per Common Unit

The following tables provide a reconciliation of the numerator and denominator of the basic and diluted earnings per common unit computations for the three months ended March 31, 2013 and 2012:

	Three Months Ended March 31,					
	2013			2012		
	Loss (Numerator)	Units (Denominator)	Per-Unit Amount	Income (Numerator)	Units (Denominator)	Per-Unit Amount
Basic (loss) income per unit						
Limited Partners' interest in net (loss) income	$(9)	170,952,804	$(0.06)	$23	158,690,035	$0.15
Effect of Dilutive Securities:						
Common unit options	—	—		—	21,129	
Phantom units *	—	—		—	361,550	
Diluted (loss) income per unit	$(9)	170,952,804	$(0.06)	$23	159,072,714	$0.14

* Amount assumes maximum conversion rate for market condition awards.

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

	Three Months Ended March 31,	
	2013	2012
Common unit options	12,854	—
Phantom units	267,820	—
Series A Preferred Units	4,665,683	4,638,732

3. Investment in Unconsolidated Affiliates

As of March 31, 2013, the Partnership has a 49.99% general partner interest in HPC, a 50% membership interest in MEP, a 30% membership interest in Lone Star, and a 33.33% membership interest in Ranch JV. The carrying value of the Partnership's investment in each of the unconsolidated affiliates as of March 31, 2013 and December 31, 2012 is as follows:

	March 31, 2013	December 31, 2012
HPC	$643	$650
MEP	572	581
Lone Star	975	948
Ranch JV	36	35
	$2,226	$2,214

The following tables summarize the Partnership's investment activities in each of the unconsolidated affiliates for the three months ended March 31, 2013 and 2012:

	Three Months Ended March 31, 2013			
	HPC	MEP	Lone Star	Ranch JV
Contributions to unconsolidated affiliates	$—	$—	$27	$1
Distributions from unconsolidated affiliates	(16)	(19)	(17)	—
Share of earnings of unconsolidated affiliates' net income	9	11	16	—

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	Three Months Ended March 31, 2012			
	HPC	MEP	Lone Star	Ranch JV
Contributions to unconsolidated affiliates	$—	$—	$80	$13
Distributions from unconsolidated affiliates	(16)	(19)	(7)	—
Share of earnings of unconsolidated affiliates' net income	11	11	11	—

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, 2013 and 2012:

	Three Months Ended March 31, 2013			
	HPC	MEP	Lone Star	Ranch JV
Total revenues	$40	$65	$358	$3
Operating income	20	34	56	—
Net income	20	21	55	—

	Three Months Ended March 31, 2012			
	HPC	MEP	Lone Star	Ranch JV
Total revenues	$42	$66	$167	$—
Operating income	23	34	39	—
Net income	23	21	38	—

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 overall management 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 supply and demand as well as market forces. Both the Partnership's profitability and cash flow are affected by the inherent volatility of these commodities which could adversely affect its ability to make distributions to its unitholders. The Partnership manages this commodity price exposure through an integrated strategy that includes management of its contract portfolio, matching sales prices of commodities with purchases, optimization of its portfolio by monitoring basis and other price differentials in operating areas, and the use of derivative contracts. In some cases, the Partnership may not be able to match pricing terms or cover its risk to price exposure with financial hedges, and it may be exposed to commodity price risk. Speculative positions with derivative contracts are prohibited under the Partnership's policies.

The Partnership has swap contracts that settle against certain NGLs, condensate and natural gas market 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.

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, 2013, the Partnership had $371 million of outstanding borrowings exposed to variable interest rate risk.

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

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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 failed to perform under existing swap contracts, the Partnership's maximum loss as of March 31, 2013 would be $2 million, which would be reduced by $1 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, 2013 and December 31, 2012 are detailed below:

	Assets		Liabilities	
	March 31, 2013	December 31, 2012	March 31, 2013	December 31, 2012
Derivatives not designated as cash flow hedges:				
Current amounts				
Commodity contracts	$2	$4	$3	$1
Long-term amounts				
Commodity contracts	1	1	—	—
Embedded derivatives in Series A Preferred Units	—	—	39	25
Total derivatives	$3	$5	$42	$26

The Partnership’s statements of operations for the three months ended March 31, 2013 and 2012 were impacted by derivative instruments activities as follows:

		Three Months Ended March 31,	
		2013	2012
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)
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	$(3)	$3
Embedded derivatives in Series A Preferred Units	Other income & deductions, net	(14)	—
		$(17)	$3

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5. Long-term Debt

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

	March 31, 2013	December 31, 2012
Senior notes	$1,965	$1,965
Revolving loans	371	192
Total	2,336	2,157
Less: current portion	—	—
Long-term debt	$2,336	$2,157
Availability under revolving credit facility:		
Total credit facility limit	$1,150	$1,150
Revolving loans	(371)	(192)
Letters of credit	(12)	(12)
Total available	$767	$946

Long-term debt maturities as of March 31, 2013 for each of the next five years are as follows:

Years Ending December 31,	Amount	
2013 (remainder)	$—	
2014	371	
2015	—	
2016	162	
2017	—	
Thereafter	1,800	
Total	$2,333	*

*Excludes unamortized premium of $3 million as of March 31, 2013.

Revolving Credit Facility. The weighted average interest rate on the total amounts outstanding under the Partnership's revolving credit facility was 3.02% and 3.09% as of March 31, 2013 and 2012, respectively.

Senior Notes. In April 2013, in conjunction with the closing of the SUGS Acquisition, the Partnership and Finance Corp. issued $600 million senior notes in a private placement, that mature on November 1, 2023 (the "2023 4.5% Notes"). The 2023 4.5% Notes bear interest at 4.5% payable semi-annually in arrears on May 1 and November 1, commencing November 1, 2013.

At any time prior to August 1, 2023, we may redeem some or all of the 2023 4.5% Notes at a price equal to 100% of the principal amount plus a make-whole premium and accrued interest. On or after August 1, 2023, we may redeem some or all of the 2023 4.5% Notes at a price equal to 100% plus accrued interest.

Upon a change of control, as defined in the indenture, followed by a ratings decline within 90 days, each holder of the 2023 4.5% Notes will be entitled to require us to purchase all or a portion of its notes at a purchase price of 101% of the principal amount plus accrued interest and liquidated damages, if any. Our ability to purchase the notes upon a change of control will be limited by the terms of our debt agreements, including our revolving credit facility.

The 2023 4.5% Notes contain various covenants that limit, among other things, our ability, and the ability of certain of our subsidiaries, to:

- incur additional indebtedness;
- pay distributions on, or repurchase or redeem equity interest;
- make certain investments;
- incur liens;
- enter into certain types of transactions with affiliates; and

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- sell assets, consolidate or merge with or into other companies.

If the 2023 4.5% Notes achieve investment grade ratings by both Moody's and S&P and no default or event or default has occurred and is continuing, we will no longer be subject to many of the foregoing covenants.

The 2023 4.5% Notes are jointly and severally guaranteed by all of our consolidated subsidiaries, other than Finance Corp. and a minor subsidiary. PEPL Holdings provided a guarantee of collection with respect to the payment of the principal amounts of the senior notes issued by us. The senior notes and the guarantees are unsecured and rank equally with all of our and the guarantors' existing and future unsecured obligations. The senior notes and the guarantees will be senior in right of payment to any of our and the guarantor's future obligations that are, by their terms, expressly subordinated in right of payment to the notes and the guarantees. The senior notes and the guarantees will be effectively subordinated to our and the guarantors' secured obligations, including our revolving credit facility, to the extent of the value of the assets securing and obligations.

In April 2013, the Partnership delivered notice of redemption to the holders of the 9.375% 2016 Notes. The Partnership will redeem all of the $162 million outstanding 2016 Notes on June 3, 2013 for cash equal to 104.688% of the principal amount, together with accrued and unpaid interest up to, but not including the redemption date. The Partnership expects that payments made in excess of outstanding principal will equal $15 million (including accrued and unpaid interest of approximately $7 million and other fees and expenses).

At March 31, 2013, the Partnership was in compliance with all covenants.

Finance Corp. has no operations and will not have revenues other than as may be incidental as co-issuer of the Senior Notes. Since the guarantees are fully unconditional and joint and several of its subsidiaries, except for a few minor subsidiaries, 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 appealed the verdict and on December 2, 2012, the appellate court affirmed the trial court's judgment. Keyes filed a motion for rehearing of the appellate court's ruling, and the court denied rehearing. Plaintiffs had until February 22, 2013 to seek review before the Texas Supreme Court but did not do so. All appeals have been exhausted and the trial court judgment is now final.

7. 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 service agreement had a five year term which was to expire 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. On April 30, 2013, in conjunction with the SUGS Acquisition, the Partnership entered into the first amendment (the “Services Agreement Amendment”) to the Services Agreement, effective as of May 26, 2010, by and among the Partnership, ETE and Services Co. The Services Agreement Amendment provides for a waiver of the $10 million annual fee effective as of May 1, 2013 through and including April 30, 2015 and clarifies the scope and expenses chargeable as direct expenses thereunder.

The Partnership, together with the General Partner and RGS entered into an operation and service agreement (the “Operations Agreement”) with ETC. On April 30, 2013, the Partnership entered into the second amendment (the “Operation and Service Amendment”) to the Operation and Service Agreement, dated May 19, 2011, as amended

November 1, 2011 (the “Operation and Service Agreement”), by and among the Partnership, ETC, the General Partner and RGS. Under the Operation and Service Agreement, ETC performs certain operations, maintenance and related services reasonably required to operate and maintain certain facilities owned by the Partnership, and the Partnership reimburses 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 Operation and Service Agreement

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Amendment provides that ETC will no longer provide the Partnership with such services for the Partnership's west Texas facilities or for certain south Texas facilities and also provides for the winding down of the remaining services during the course of the year.
The Partnership incurred total service fees of $4 million for each of the three months ended March 31, 2013 and 2012, respectively.
In conjunction with distributions by the Partnership to the limited and general partner interests, ETE received cash distributions of $15 million for each of the three months ended March 31, 2013 and 2012, 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 Services segment provides contract compression and treating services to subsidiaries of ETP and records revenue in gathering, transportation and other fees. The Partnership's Contract Compression segment sold no compression equipment to subsidiaries of ETP during the three months ended March 31, 2013. The Partnership's Contract Services segment purchased compression equipment from a subsidiary of ETP for $14 million for the three months ended March 31, 2013.
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 were $5 million and $4 million for the three months ended March 31, 2013 and 2012, respectively, which are recorded in gathering, transportation and other fees.
The Partnership's Contract Services segment provides 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.

8. Segment Information

During the fourth quarter of 2012, the Partnership realigned the composition of its segments and updated the segment names to reflect the realignment. Accordingly, the Partnership has restated the items of segment information for the three months ended March 31, 2012 to reflect this new segment alignment.
The Partnership has five reportable segments: Gathering and Processing, Natural Gas Transportation, NGL Services, Contract Services, and Corporate. The reportable segments are as described below:

- Gathering and Processing. The Partnership provides “wellhead-to-market” services to producers of natural gas, which include transporting raw natural gas from the wellhead through gathering systems, processing raw natural gas to separate NGLs from the raw natural gas and selling or delivering pipeline-quality natural gas and NGLs to various markets and pipeline systems. This segment also includes the Partnership's 33.33% membership interest in Ranch JV, which processes natural gas delivered from the NGLs-rich Bone Spring and Avalon shale formations in west Texas.
- Natural Gas Transportation. The Partnership owns 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, and 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. This segment also includes Gulf States, which owns a 10-mile interstate pipeline that extends from Harrison County, Texas to Caddo Parish, Louisiana.
- NGL Services. The Partnership owns a 30% membership interest in Lone Star, an entity owning a diverse set of midstream energy assets including pipelines, storage, fractionation and processing facilities located in Texas, Mississippi and Louisiana.
- Contract Services. The Partnership owns and operates a fleet of compressors used to provide turn-key natural gas compression services for customer specific systems. The Partnership also 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.
- Corporate. The Corporate segment comprises the Partnership's corporate assets.

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 Natural Gas Transportation segments is defined as total revenues, including service fees, less cost of sales. In the Contract Services segment, segment margin is defined as revenues less direct costs.

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Management believes segment margin is an important measure because it directly relates to volume, commodity price changes and revenue generating horsepower. Operation and maintenance expenses are a separate measure used by management to evaluate performance of field operations. Direct labor, insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of operation and maintenance expenses. These expenses fluctuate depending on the activities performed during a specific period. The Partnership does not deduct operation and maintenance expenses from total revenues in calculating segment margin because management separately evaluates commodity volume and price changes in segment margin. The Partnership does not record segment margin for its investments in unconsolidated affiliates (HPC, MEP, Lone Star and Ranch JV) because it records its ownership percentages of their net income as income from unconsolidated affiliates in accordance with the equity method of accounting.

Results for each segment are shown below:

	Three Months Ended March 31,	
	2013	2012
External Revenues		
Gathering and Processing	$295	$307
Natural Gas Transportation	—	—
NGL Services	—	—
Contract Services	49	47
Corporate	5	4
Eliminations	—	—
Total	$349	$358
Intersegment Revenues		
Gathering and Processing	$—	$—
Natural Gas Transportation	—	—
NGL Services	—	—
Contract Services	3	5
Corporate	—	—
Eliminations	(3)	(5)
Total	$—	$—
Segment Margin		
Gathering and Processing	$71	$71
Natural Gas Transportation	—	1
NGL Services	—	—
Contract Services	47	47
Corporate	5	4
Eliminations	(3)	(5)
Total	$120	$118
Operation and Maintenance		
Gathering and Processing	$31	$28
Natural Gas Transportation	—	—
NGL Services	—	—
Contract Services	17	18
Corporate	—	—
Eliminations	(3)	(5)
Total	$45	$41

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

	Three Months Ended March 31,	
	2013	2012
Total segment margin	$120	$118
Operation and maintenance	(45)	(41)
General and administrative	(17)	(16)
Loss on asset sales, net	(1)	—
Depreciation and amortization	(48)	(51)
Income from unconsolidated affiliates	35	32
Interest expense, net	(37)	(30)
Other income and deductions, net	(14)	17 *
(Loss) income before income taxes	$(7)	$29

* Other income and deductions, net for the three months ended March 31, 2012 included a one-time producer payment of $16 million related to an assignment of certain contracts.

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

	March 31, 2013	December 31, 2012
Gathering and Processing	$2,313	$2,244
Natural Gas Transportation	1,216	1,232
NGL Services	975	948
Contract Services	1,715	1,672
Corporate	54	61
Total	$6,273	$6,157

Investment in Unconsolidated Affiliates	March 31, 2013	December 31, 2012
Gathering and Processing	$35	$35
Natural Gas Transportation	1,216	1,231
NGL Services	975	948
Contract Services	—	—
Corporate	—	—
Total	$2,226	$2,214

9. 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 $2 million and $1 million was recorded in general and administrative expense for the three months ended March 31, 2013 and 2012, respectively.

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 or (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. During the three months ended March 31, 2013, all remaining market condition grants were forfeited due to the completion of the three years vesting period without attaining the market based incentive requirements.

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All phantom units granted from November 2010 to November 2012 were service condition grants with graded vesting over five years. Phantom units granted after November 2012 were service condition grants that (1) have graded vesting over five years or (2) vest over the next five years on a cliff basis; by vesting 60% at the end of the third year of service and vesting the remaining 40% at the end of the fifth year of service. 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, 2013:

Phantom Units	Units		Weighted Average Grant Date Fair Value
Outstanding at beginning of period	1,231,342		$ 23.22
Service condition grants	23,824		24.19
Vested service condition	(17,909	)	22.48
Forfeited service condition	(14,000	)	23.22
Forfeited market condition	(44,397	)	19.52
Outstanding at end of period	1,178,860		23.39

The Partnership expects to recognize $23 million of compensation expense related to non-vested phantom units over a period of 5 years.

10. 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 and embedded derivatives in the Series A Preferred Units. Derivatives related to commodity swaps are valued using discounted cash flow techniques. These techniques incorporate Level 1 and Level 2 inputs such as 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, 2013			Fair Value Measurements at December 31, 2012		
	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	$—	$—	$—	$ 2	$ 2	$—
NGLs	1	1	—	1	1	—
Condensate	2	2	—	2	2	—
Total Assets	$3	$3	$—	$ 5	$ 5	$—
Liabilities:						
Commodity Derivatives:						
Natural Gas	$3	$3	$—	$—	$—	$—
NGLs	—	—	—	1	1	—
Embedded Derivatives in Series A Preferred Units	39	—	39	25	—	25
Total Liabilities	$42	$3	$ 39	$ 26	$ 1	$ 25

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

Unobservable Input	March 31, 2013	
Credit Spread	6.47	%
Volatility	20.15	%

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, 2013. There were no transfers between the fair value hierarchy levels for the three months ended March 31, 2013.

	Embedded Derivatives in Series A Preferred Units
Balance at December 31, 2012	$25
Change in fair value	14
Balance at March 31, 2013	$39

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 aggregate fair value and carrying amount of the Senior Notes at March 31, 2013 was $2.12 billion and $1.96 billion, respectively. As of December 31, 2012, the aggregate fair value and carrying amount of the Senior Notes was $2.13 billion and $1.96 billion, respectively. The fair value of the Senior Notes is a Level 1 valuation based on third party market value quotations.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

(Tabular dollar amounts are in millions)

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, 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, Utica, Bone Spring, Avalon and Granite Wash shales. Our assets are primarily located in Texas, Louisiana, Arkansas, Pennsylvania, California, Mississippi, Alabama, New Mexico, and the mid-continent region of the United States, which includes Kansas, Colorado and Oklahoma.

RECENT DEVELOPMENTS.

SUGS Acquisition. On April 30, 2013, we and Regency Western acquired SUGS from Southern Union, a wholly owned subsidiary of Holdco, for approximately $1.5 billion. We financed the acquisition by issuing to Holdco 31 million of our common units and 6 million recently created Class F common units. The Class F common units are not entitled to participate in the Partnership's distributions for twenty-four months post-transaction closing. The remaining $600 million, less $107 million of estimated closing adjustments, was paid in cash. In addition, in conjunction with the acquisition, ETE has agreed to forgo IDR payments on the common units issued with this transaction for the twenty-four months post-transaction closing and to eliminate the $10 million annual management fee paid by us for two years post-transaction close.

Upon closing, the SUGS Acquisition will expand our presence in the Permian Basin in west Texas, one of the most prolific, high growth, oil and liquids-rich basins in North America.

The common units and Class F common units related to the SUGS Acquisition were issued in a private placement conducted in accordance with the exemption from registration requirements of the Securities Act of 1933, as amended under Section 4(e) thereof. The Class F common units will convert into common units on a one-for-one basis in May 2015.

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The cash portion of the SUGS Acquisition was funded from the proceeds of senior notes issued by the Partnership on April 30, 2013 in a private placement. PEPL Holdings provided a guarantee of collection with respect to the payment of the principal amounts of the senior notes issued by the Partnership.

Because the SUGS Acquisition is a transaction between commonly controlled entities (i.e., the buyer and the sellers are each affiliates of ETE), we will be required to account for the acquisition in a manner similar to the pooling of interest method of accounting. Under this method of accounting, we will reflect historical balance sheet data for both us and SUGS instead of reflecting the fair market value of SUGS assets and liabilities. We will retrospectively adjust its financial statements to include the operations of SUGS from March 26, 2012 (the date upon which common control began), beginning with the first issuance of financial statements for periods including the consummation of the transaction.

Senior Notes Redemption. In April 2013, we delivered notice of redemption to the holders of our 2016 Notes. We will redeem all of the $162 million outstanding 9.375% 2016 Notes on June 3, 2013 for cash equal to 104.688% of the principal amount, together with accrued and unpaid interest up to, but not including the redemption date. We expect that payments made in excess of outstanding principal will equal $15 million (including accrued and unpaid interest of approximately $7 million and other fees and expenses). We will use borrowings under our revolving credit facility to fund this redemption.

OUR OPERATIONS. We divide our operations into five business segments. During the fourth quarter of 2012, the Partnership realigned the composition of its segments and updated the segment names to reflect the realignment. Accordingly, we have restated segment information for earlier periods to reflect this new segment alignment as follows:

- Gathering and Processing. We provide “wellhead-to-market” services to producers of natural gas, which include transporting raw natural gas from the wellhead through gathering systems, processing raw natural gas to separate NGLs from the raw natural gas and selling or delivering the pipeline-quality natural gas and NGLs to various markets and pipeline systems. This segment also includes ELG and our 33.33% membership interest in Ranch JV, which processes natural gas delivered from the NGLs-rich Bone Spring and Avalon shale formations in west Texas.
- Natural Gas Transportation. We own a 49.99% general partner interest in HPC, which owns RIGS, a 450 mile intrastate pipeline that delivers natural gas from northwest Louisiana to downstream pipelines and markets, and 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. This segment also includes Gulf States, which owns a 10-mile interstate pipeline that extends from Harrison County, Texas to Caddo Parish, Louisiana.
- NGL Services. We own a 30% membership interest in Lone Star, an entity owning a diverse set of midstream energy assets including pipelines, storage, fractionation and processing facilities located in Texas, Mississippi and Louisiana.
- Contract Services. We own and operate a fleet of compressors used to provide turn-key natural gas compression services for customer specific systems. We also 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.
- Corporate. The Corporate segment comprises our corporate assets.

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, revenue generating horsepower 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 Natural Gas Transportation 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 our investments in unconsolidated affiliates (HPC, MEP, Lone Star, and Ranch JV) because we record our ownership percentage of their net income as income from unconsolidated affiliates in accordance with the equity method of accounting.

We calculate our Contract Services segment margin as our revenues generated from our contract compression and treating operations minus direct costs, primarily repairs, associated with those revenues.

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

Adjusted Segment Margin and Adjusted Total Segment Margin. We define adjusted segment margin as segment margin adjusted for non-cash (gains) losses from commodity derivatives, the 40% of ELG margin attributable to the holder of the noncontrolling interest and our 33.33% portion of Ranch JV margin. Our adjusted total segment margin equals the sum of our operating segments' adjusted segment margins or segment margins, including intersegment eliminations. Adjusted segment margin and adjusted total segment margin are included as supplemental disclosures because they are primary performance measures used by management as they represent the results of product purchases and sales, a key component of our operations.

Revenue Generating Horsepower. Revenue generating horsepower is the primary driver for revenue growth in compression services for our Contract Service segment, and it is also the primary measure for evaluating our operational efficiency. Revenue generating horsepower is the total horsepower that our Contract Services segment owns and operates for external customers. It does not include horsepower under contract that is not generating revenue or idle horsepower.

Operation and Maintenance Expense. Operation and maintenance expense is a separate measure that we use to evaluate operating performance of field operations. Direct labor, insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of our operating and maintenance expense. These expenses are largely independent of the volumes through our systems but fluctuate depending on the activities performed during a specific period. We do not deduct operation and maintenance expense 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, provision for income taxes and depreciation and amortization expense. We define adjusted EBITDA as EBITDA plus or minus the following:

- non-cash loss (gain) from commodity and embedded derivatives;
- non-cash unit-based compensation;
- loss (gain) on asset sales, net;
- loss on debt refinancing;
- other non-cash (income) expense, net;
- net income attributable to ELG;
- Partnership's interest in ELG adjusted EBITDA; 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 and the overall rates of return on alternative investment opportunities.

Neither EBITDA nor adjusted EBITDA should be considered 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 and adjusted EBITDA may not be comparable to a similarly titled measure of another company because other entities may not calculate EBITDA or adjusted EBITDA in the same manner.

Adjusted EBITDA is the starting point in determining cash available for distribution, which is an important non-GAAP financial measure for a publicly traded partnership.

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

	Three Months Ended March 31,	
Reconciliation of "Adjusted EBITDA" to net cash flows provided by operating activities and net (loss) income	2013	2012
Net cash flows provided by operating activities	$67	$56
Add (deduct):		
Depreciation and amortization, including debt issuance cost amortization and bond premium amortization	(50)	(54)
Income from unconsolidated affiliates	35	32
Derivative valuation change	(18)	3
Loss on asset sales, net	(1)	—
Unit-based compensation expenses	(2)	(1)
Trade accounts receivable, accrued revenues and related party receivables	8	(7)
Other current assets and other current liabilities	(13)	(5)
Trade accounts payable, accrued cost of gas and liquids, related party payables and deferred revenues	4	34
Distributions of earnings received from unconsolidated affiliates	(36)	(29)
Cash flow changes in other assets and liabilities	1	—
Net (loss) income	(5)	29
Add (deduct):		
Interest expense, net	37	30
Depreciation and amortization expense	48	51
Income tax benefit	(2)	—
EBITDA	78	110
Add (deduct):		
Non-cash loss (gain) from commodity and embedded derivatives	18	(2)
Unit-based compensation expenses	2	1
Loss on asset sales, net	1	—
Income from unconsolidated affiliates	(35)	(32)
Partnership's interest in unconsolidated affiliates' adjusted EBITDA	63	57
Adjusted EBITDA	$127	$134

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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, 2013 and 2012:

	Three Months Ended March 31, 2013				
	HPC	MEP	Lone Star	Ranch JV	Total
Net income	$20	$21	$55	$—	
Add:					
Depreciation and amortization	9	17	20	1	
Interest expense, net	—	13	—	—	
Other expenses	—	—	1	—	
Adjusted EBITDA	29	51	76	1	
Ownership interest	49.99 %	50 %	30 %	33.33 %	
Partnership's interest in adjusted EBITDA	$14	$26	$23	$—	$63

	Three Months Ended March 31, 2012				
	HPC	MEP	Lone Star	Ranch JV	Total
Net income	$23	$22	$38	$—	
Add:					
Depreciation and amortization	9	17	12	—	
Interest expense, net	—	13	—	—	
Other expenses	—	—	1	—	
Adjusted EBITDA	32	52	51	—	
Ownership interest	49.99 %	50 %	30 %	33.33 %	
Partnership's interest in adjusted EBITDA	$16	$26	$15	$—	$57

The following table presents a reconciliation of total segment margin and adjusted total segment margin to net (loss) income for the three month periods ended March 31, 2013 and 2012 for the Partnership:

	Three Months Ended March 31,	
	2013	2012
Net (loss) income	$(5)	$29
Add (deduct):		
Operation and maintenance	45	41
General and administrative	17	16
Loss on asset sales, net	1	—
Depreciation and amortization	48	51
Income from unconsolidated affiliates	(35)	(32)
Interest expense, net	37	30
Other income and deductions, net	14	(17)
Income tax benefit	(2)	—
Total segment margin	120	118
Add (deduct):		
Non-cash loss (gain) from commodity derivatives	4	(2)
Segment margin related to noncontrolling interest	(2)	(1)
Segment margin related to ownership percentage in Ranch JV	1	—
Adjusted total segment margin	$123	$115

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RESULTS OF OPERATIONS

Three Months Ended March 31, 2013 vs. Three Months Ended March 31, 2012

	Three Months Ended March 31,			
	2013	2012	Change	Percent
Total revenues	$349	$358	$(9)	3 %
Cost of sales	229	240	11	5
Total segment margin [1]	120	118	2	2
Operation and maintenance	45	41	(4)	10
General and administrative	17	16	(1)	6
Loss on asset sales, net	1	—	(1)	—
Depreciation and amortization	48	51	3	6
Operating income	9	10	(1)	10
Income from unconsolidated affiliates	35	32	3	9
Interest expense, net	(37)	(30)	(7)	23
Other income and deductions, net	(14)	17	(31)	182
(Loss) income before income taxes	(7)	29	(36)	124
Income tax benefit	(2)	—	2	—
Net (loss) income	(5)	29	(34)	117
Net income attributable to noncontrolling interest	—	—	—	—
Net (loss) income attributable to Regency Energy Partners LP	$(5)	$29	$(34)	117
Gathering and processing segment margin	$71	$71	$—	—
Non-cash loss (gain) from commodity derivatives	4	(2)	6	300
Segment margin related to noncontrolling interest	(2)	(1)	(1)	100
Segment margin related to ownership percentage in Ranch JV	1	—	1	—
Adjusted gathering and processing segment margin	74	68	6	9
Natural gas transportation segment margin	—	1	(1)	—
Contract services segment margin [2]	47	47	—	—
Corporate segment margin	5	4	1	25
Intersegment eliminations [2]	(3)	(5)	2	40
Adjusted total segment margin	$123	$115	$8	7 %

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

(2) Contract Services segment margin includes intersegment revenues of $3 million and $5 million for the three months ended March 31, 2013 and 2012, respectively. These intersegment revenues were eliminated upon consolidation.

Net (Loss) Income Attributable to Regency Energy Partners LP. We had a net loss of $5 million for the three months ended March 31, 2013 compared to net income of $29 million for the three months ended March 31, 2012. The primary reason for this change was a $31 million decrease in other income and deductions, net primarily due to a $14 million non-cash loss on the mark-to-market of the embedded derivative related to the Series A Preferred Units in March 2013 and the absence of a $16 million one-time producer payment received in March 2012 related to an assignment of certain contracts.

Adjusted Total Segment Margin. Adjusted total segment margin increased to $123 million in the three months ended March 31, 2013 from $115 million in the three months ended March 31, 2012. The major components of this change were as follows:

- Adjusted Gathering and Processing segment margin increased to $74 million during the three months ended March 31, 2013 from $68 million for the three months ended March 31, 2012 primarily due to volume growth in south and west Texas and north Louisiana. Total Gathering and Processing throughput increased to 1,517,000 MMBtu/d during the three months ended March 31, 2013 from 1,366,000 MMBtu/d during the three months ended March 31, 2012. Total NGL gross production

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increased to 43,000 Bbls/d during the three months ended March 31, 2013 from 38,000 Bbls/d during the three months ended March 31, 2012;

- Contract Services segment margin remained flat at $47 million in the three months ended March 31, 2013 as compared to the three months ended March 31, 2012. As of March 31, 2013 and 2012, total revenue generating horsepower was 891,000 and 843,000, inclusive of 38,000 and 82,000, respectively, of revenue generating horsepower utilized by our Gathering and Processing segment; and
- Intersegment eliminations decreased to $3 million in the three months ended March 31, 2013 from $5 million in the three months ended March 31, 2012. The decrease was primarily due to a decrease in intersegment revenue between the Gathering and Processing segment and the Contract Services segment associated with certain assets in south Texas.

Operation and Maintenance. Operation and maintenance expense increased to $45 million in the three months ended March 31, 2013 from $41 million during the three months ended March 31, 2012. The change was primarily due to the following:

- $3 million increase in employee expenses primarily due to organic growth in south and west Texas and an increase in employee headcount;
- $2 million increase in materials and supplies, primarily related to plant and compressor materials and maintenance costs;
- $1 million increase in ad valorem taxes primarily related to our organic growth projects; offset by
- $2 million decrease in contractor expenses.

General and Administrative. General and administrative expense increased to $17 million in the three months ended March 31, 2013 from $16 million during the three months ended March 31, 2012. The change was primarily due to a $1 million increase in transaction costs related to the SUGS Acquisition.

Depreciation and Amortization. Depreciation and amortization expense decreased to $48 million in the three months ended March 31, 2013 from $51 million in the three months ended March 31, 2012. This decrease was the result of the absence of $7 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, 2012) related to our Contract Services segment to adjust the estimated useful lives of certain assets to comply with our policy, offset by $4 million of additional depreciation and amortization expense due to the completion of various organic growth projects since April 2012. Had these amounts been recorded in their respective period, the depreciation and amortization expense for the quarter ended March 31, 2012 would have been $44 million.

Income from Unconsolidated Affiliates. Income from unconsolidated affiliates increased to $35 million for the three months ended March 31, 2013 from $32 million for the three months ended March 31, 2012. The schedule below summarizes the components of income from unconsolidated affiliates and our ownership interest for the three months ended March 31, 2013 and 2012, respectively:

	Three Months Ended March 31, 2013				
	HPC	MEP	Lone Star	Ranch JV	Total
Net income	$20	$21	$55	$—	
Ownership interest	49.99 %	50 %	30 %	33.33 %	
Share of unconsolidated affiliates’ net income	9	11	16	—	
Less: Amortization of excess fair value of unconsolidated affiliates	(1)	—	—	—	
Income from unconsolidated affiliates	$8	$11	$16	$—	$35

	Three Months Ended March 31, 2012				
	HPC	MEP	Lone Star	Ranch JV	Total
Net income	$23	$21	$38	$—	
Ownership interest	49.99 %	50 %	30 %	33.33 %	
	11	11	11	—	

Share of unconsolidated affiliates' net income					
Less: Amortization of excess fair value of unconsolidated affiliates	(1)	—	—	—	
Income from unconsolidated affiliates	$10	$11	$11	$—	$32

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HPC’s net income decreased to $20 million for the three months ended March 31, 2013 from $23 million for the three months ended March 31, 2012, primarily due to the expiration of certain contracts that were not renewed as well as a customer declaring bankruptcy on April 1, 2013, which contributed $1 million to the decrease. We expect that the annual impact resulting from the loss of this customer, if they do not successfully recover and we are unable to replace the firm commitment contract, would be a reduction of approximately $5 million. MEP's net income remained flat at $21 million for the three months ended March 31, 2013 and the three months ended March 31, 2012. Lone Star's net income increased to $55 million for the three months ended March 31, 2013 from $38 million for the three months ended March 31, 2012, primarily due to the addition of the West Texas Gateway NGL Pipeline and Lone Star Fractionator I placed into service in December 2012.

The following table presents operational data for each of our unconsolidated affiliates for the three months ended March 31, 2013 and 2012:

		Three Months Ended March 31,	
	Operational data	2013	2012
HPC	Throughput (MMBtu/d)	714,114	941,139
MEP	Throughput (MMBtu/d)	1,463,347	1,429,103
Lone Star	NGL Transportation – Total Volumes (Bbls/d)	153,493	134,616
	Refinery – Geismar Throughput (Bbls/d)	17,232	19,245
	Fractionation – Throughput Volume (Bbls/d)	50,997	*
Ranch JV	Throughput (MMBtu/d)	53,443	**

*Fractionator I began operations in December 2012.

**Ranch JV had not begun operations.

Interest Expense, Net. Interest expense, net increased to $37 million for the three months ended March 31, 2013 from $30 million for the three months ended March 31, 2012, primarily due to the interest related to our $700 million senior notes issued in October 2012 with an interest rate of 5.5%.

Other Income and Deductions, Net. Other income and deductions, net decreased to a loss of $14 million in the three months ended March 31, 2013 from a gain of $17 million in the three months ended March 31, 2012, primarily due to the absence of a $16 million one-time producer payment received in March 2012 related to an assignment of certain contracts and a $14 million non-cash loss on the mark-to-market of the embedded derivative related to the Series A Preferred Units in March 2013.

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, 2012.

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.

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LIQUIDITY AND CAPITAL RESOURCES

Liquidity

We expect our sources of liquidity to include:

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

We expect our 2013 capital expenditures, including capital contributions to our unconsolidated affiliates and SUGS, to be as follows (in millions):

	2013
Growth Capital Expenditures	
Gathering and Processing segment	$410
NGL Services segment	130
Contract Services segment	145
Total	$685
Maintenance Capital Expenditures; including our proportionate share related to our unconsolidated affiliates	$45

We may revise the timing of these expenditures as necessary to adapt to economic or business 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 the fair value changes of current derivative assets and liabilities. These derivative assets and liabilities represent our expectations for the settlement of derivative rights and obligations over the next 12 months, and should be viewed differently from trade accounts receivable and accounts payable, which settle over a shorter span of time. When our derivative positions are settled, we expect an offsetting physical transaction, and, as a result, we do not expect derivative assets and liabilities to affect our ability to pay expenditures and obligations as they come due. Our Contract Services segment records 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 deficit of $61 million at March 31, 2013 compared to a working capital deficit of $50 million at December 31, 2012. This deficit was primarily due to a $15 million increase in other current liabilities due to an increase in accrued interest, a $9 million decrease in cash and cash equivalents, offset by an $11 million decrease in related party payables net of related party receivables.

Cash Flows from Operating Activities. Net cash flows provided by operating activities increased to $67 million in the three months ended March 31, 2013 from $56 million in the three months ended March 31, 2012, primarily as a result of an increase in operating cash flow generated by changes in current assets and liabilities, the non-cash derivative value change, and an increase in distributions of earnings received from unconsolidated affiliates, offset by a decrease in net income to a net loss.

Cash Flows used in Investing Activities. Net cash flows used in investing activities increased to $182 million in the three months ended March 31, 2013 from $130 million in the three months ended March 31, 2012, primarily as a result of increased capital expenditures 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, 2013, we incurred $174 million of growth capital expenditures. Growth capital expenditures for the three

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months ended March 31, 2013 were primarily related to $80 million for our Gathering and Processing segment, $28 million for our NGL Services segment, and $66 million for our Contract Services 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, 2013, we incurred $7 million of maintenance capital expenditures.

Cash Flows from Financing Activities. Net cash flows provided by financing activities decreased to $106 million in the three months ended March 31, 2013 from $139 million during the same period in 2012. The decrease is primarily due to our issuing common units resulting in net proceeds of $297 million in March 2012, offset by borrowings under our revolving credit facility and increased Partnership distributions, in the three months ended March 31, 2013.

Capital Resources

Common Unit Offering. In April 2013, in conjunction with the closing of the SUGS Acquisition, we issued 31 million common units and 6 million newly created Class F common units. The common units and Class F common units related to the SUGS Acquisition were issued in a private placement conducted in accordance with the exemption from registration requirements of the Securities Act of 1933, as amended under Section 4(e) thereof. The Class F common units will convert into common units on a one-for-one basis in May 2015.

Senior Notes Offering. In April 2013, in conjunction with the closing of the SUGS Acquisition, we issued $600 million senior notes in a private placement, due November 1, 2023.The 2023 4.5% Notes bear interest at 4.5% payable semi-annually in arrears on May 1 and November 1, commencing November 1, 2013.

At any time prior to August 1, 2023, we may redeem some or all of the 2023 4.5% Notes at a price equal to 100% of the principal amount plus a make-whole premium and accrued interest. On or after August 1, 2023, we may redeem some or all of the 2023 4.5% Notes at a price equal to 100% plus accrued interest.

Upon a change of control, as defined in the indenture, followed by a ratings decline within 90 days, each holder of the 2023 4.5% Notes will be entitled to require us to purchase all or a portion of its notes at a purchase price of 101% of the principal amount plus accrued interest and liquidated damages, if any. Our ability to purchase the notes upon a change of control will be limited by the terms of our debt agreements, including our revolving credit facility.

The 2023 4.5% Notes contain various covenants that limit, among other things, our ability, and the ability of certain of our subsidiaries, to:

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

If the 2023 4.5% Notes achieve investment grade ratings by both Moody's and S&P and no default or event or default has occurred and is continuing, we will no longer be subject to many of the foregoing covenants.

The 2023 4.5% Notes are jointly and severally guaranteed by all of our consolidated subsidiaries, other than Finance Corp. and a minor subsidiary. PEPL Holdings provided a guarantee of collection with respect to the payment of the principal amounts of the senior notes issued by us. The senior notes and the guarantees are unsecured and rank equally with all of our and the guarantors' existing and future unsecured obligations. The senior notes and the guarantees will be senior in right of payment to any of our and the guarantor's future obligations that are, by their terms, expressly subordinated in right of payment to the notes and the guarantees. The senior notes and the guarantees will be effectively subordinated to our and the guarantors' secured obligations, including our revolving credit facility, to the extent of the value of the assets securing and obligations.

Senior Notes Redemption. In April 2013, we delivered notice of redemption to the holders of our 9.375% 2016 Notes. We will redeem all of the $162 million outstanding 2016 Notes on June 3, 2013 for cash equal to 104.688% of the principal amount, together with accrued and unpaid interest up to, but not including the redemption date. We expect that payments made in excess of outstanding principal will equal $15 million (including accrued and unpaid interest of approximately $7 million and other fees and expenses). We will use borrowings under our revolving credit facility to fund this redemption.

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Cash Distributions from Unconsolidated Affiliates. The following table summarizes the cash distributions from unconsolidated affiliates for the three months ended March 31, 2013 and 2012:

	Three Months Ended March 31,	
	2013	2012
HPC	$16	$16
MEP	19	19
Lone Star	17	7
	$52	$42

The increase in the Lone Star distribution is primarily attributable to the addition of the West Texas Gateway NGL Pipeline and Lone Star Fractionator I placed into service in December 2012.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

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

Commodity Price Risk. We are a net seller of NGLs, condensate and natural gas as a result of our gathering and processing operations. The prices of these commodities are impacted by changes in supply and demand as well as market forces. Our profitability and cash flow are affected by the inherent volatility of these commodities, which could adversely affect our 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 have swap contracts that settle against certain NGLs, condensate and natural gas market prices.

The following table sets forth certain information regarding our hedges outstanding at March 31, 2013. 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.

Period	Underlying	Notional Volume/ Amount		We Pay	We Receive Weighted Average Price		Fair Value Asset/ (Liability) (in millions)	Effect of Hypothetical Change in Index*
April 2013-December 2013	Propane	41	(MBbls)	Index	0.90	($/gallon)	—	—
April 2013-December 2014	Normal Butane	188	(MBbls)	Index	1.58	($/gallon)	1	1
April 2013-December 2014	West Texas Intermediate Crude	422	(MBbls)	Index	98.23	($/Bbl)	2	4
April 2013-December 2013	Natural Gas	12,257,000	(MMBtu)	Index	3.97	($/MMBtu)	(3)	5
					Total Fair Value		$—	

* 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 management's evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective in achieving that level of reasonable assurance as of March 31, 2013.

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, 2013 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, 2012. 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, 2012.

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Item 6. Exhibits
The exhibits below are filed as a part of this report:

Exhibit Number	Description	Incorporated by Reference from Form	Date Filed or File No.
Exhibit 2.1	Contribution Agreement dated as of February 27, 2013	8-K	February 28, 2013
Exhibit 2.2	Amendment No. 1 to Contribution Agreement dated as of April 16, 2013, with the related Form of Guarantee of Collection	8-K	April 16, 2013
Exhibit 4.1	Form of Time-Vested Phantom Unit Agreement	*	
Exhibit 4.2	Form of Time-Vested Phantom Unit Agreement	*	
Exhibit 4.3	Form of Restricted Common Unit Agreement	*	
Exhibit 10.1	Amendment Agreement No. 4 to the Fifth Amended and Restated Credit Agreement, dated February 15, 2013	8-K	February 19, 2013
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		

* Filed herewith
** Furnished herewith

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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, 2013

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