Tallgrass Energy Partners, LP
Form 10-Q
June 26, 2013

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

(Mark One)

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

For the Quarterly Period Ended March 31, 2013

or

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission file number 001-35917

Tallgrass Energy Partners, LP

(Exact name of registrant as specified in its charter)

Delaware	4922	46-1972941
(State or other Jurisdiction of Incorporation or Organization)	(Primary Standard Industrial Classification Code Number)	(IRS Employer Identification Number)

6640 W. 143rd Street, Suite 200

Overland Park, Kansas 66223

(913) 928-6060

(Address, including zip code, and telephone number, including area code, of Registrant s principal executive offices)

George E. Rider

6640 W. 143rd Street, Suite 200

Overland Park, Kansas 66223

(913) 928-6060

(Address, including zip code, and telephone number, including area code, of Agent for service)

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 ¨ No x

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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

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

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

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

On June 20, 2013, the Registrant had 24,300,000 Common Units, 16,200,000 Subordinated Units, and 826,531 General Partner Units outstanding.

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TALLGRASS ENERGY PARTNERS, LP

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Glossary of Common Industry and Measurement Terms

Base Gas (or Cushion Gas): The volume of gas that is intended as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates.

BBtu: One billion British Thermal Units.

Bcf: One billion cubic feet.

condensate: A NGL with a low vapor pressure, mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.

dry gas: A gas primarily composed of methane and ethane where heavy hydrocarbons and water either do not exist or have been removed through processing.

Dth: A dekatherm, which is a unit of energy equal to 10 therms or one million British thermal units.

end-user markets: The ultimate users and consumers of transported energy products.

FERC: Federal Energy Regulatory Commission.

firm transportation and storage services: Those services pursuant to which customers receive firm assurances regarding the availability of capacity and deliverability of natural gas on our assets up to a contracted amount at specified receipt and delivery points.

GAAP: Generally accepted accounting principles in the United States of America.

GHGs: Greenhouse gases.

header system: Networks of medium-to-large-diameter high pressure pipelines that connect local gathering systems to large diameter high pressure long-haul transportation pipelines.

HP: Horsepower.

interruptible transportation and storage services: Those services pursuant to which customers receive only limited assurances regarding the availability of capacity and deliverability in transportation or storage facilities, as applicable, and pay fees based on their actual utilization of such assets.

local distribution company or LDC: LDCs are involved in the delivery of natural gas to consumers within a specific geographic area.

LNG: Natural gas that has been cooled to minus 161 degrees Celsius for transportation, typically by ship. The cooling process reduces the volume of natural gas by 600 times.

Mcf: One thousand cubic feet.

MMcf: One million cubic feet.

NGLs: Those hydrocarbons in natural gas that are separated from the natural gas as liquids through the process of absorption, condensation, adsorption or other methods in natural gas processing or cycling plants. Generally such liquids consist of propane and heavier hydrocarbons and are commonly referred to as lease condensate, natural gasoline and liquefied petroleum gases. Natural gas liquids include natural gas plant liquids (primarily ethane, propane, butane and isobutane) and lease condensate (primarily pentanes produced from natural gas at lease separators and field facilities).

no-notice service: Those services pursuant to which customers receive the right to transport or store natural gas on assets outside of the daily nomination cycle without incurring penalties.

NYMEX: New York Mercantile Exchange.

park and loan services: Those services pursuant to which customers receive the right to store natural gas in (park), or borrow gas from (loan), our facilities on a seasonal basis.

PHMSA: The United States Department of Transportation s Pipeline and Hazardous Materials Safety Administration.

play: A proven geological formation that contains commercial amounts of hydrocarbons.

receipt point: The point where production is received by or into a gathering system or transportation pipeline.

reservoir: A porous and permeable underground formation containing an individual and separate natural accumulation of producible hydrocarbons (crude oil and/or natural gas) which is confined by impermeable rock or water barriers and is characterized by a single natural pressure system.

residue gas: The natural gas remaining after being processed or treated.

shale gas: Natural gas produced from organic (black) shale formations.

tailgate: The point at which processed natural gas and NGLs leave a processing facility for end-user markets.

TBtu: One trillion British Thermal Units.

Tcf: One trillion cubic feet.

throughput: The volume of natural gas transported or passing through a pipeline, plant, terminal or other facility during a particular period.

wellhead: The equipment at the surface of a well that is used to control the well s pressure; also, the point at which the hydrocarbons and water exit the ground.

working gas: The volume of gas in the reservoir that is in addition to the cushion or base gas. It may or may not be completely withdrawn during any particular withdrawal season. Conditions permitting, the total working capacity could be used more than once during any season.

working gas storage capacity: The maximum volume of natural gas that can be cost-effectively injected into a storage facility and extracted during the normal operation of the storage facility. Effective working gas storage capacity excludes cushion gas and non-cycling working gas.

x/d: The applicable measurement metric per day. For example, MMcf/d means one million cubic feet per day.

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PART 1 FINANCIAL INFORMATION

Item 1. Financial Statements

TALLGRASS ENERGY PARTNERS PREDECESSOR

AND TALLGRASS ENERGY PARTNERS PRE-PREDECESSOR

CONDENSED COMBINED STATEMENTS OF INCOME

(UNAUDITED)

	TEP Predecessor Three Months Ended March 31, 2013 (in thousands)	TEP Pre-Predecessor Three Months Ended March 31, 2012 (in thousands)
Revenues:		
Natural gas liquids sales	$ 33,401	$ 36,011
Natural gas sales	301	870
Transportation services	24,337	28,156
Other operating revenues	2,219	1,492
Total Revenues	60,258	66,529
Operating Costs and Expenses:		
Cost of sales and transportation services (exclusive of depreciation and amortization shown below)	28,884	29,435
Operations and maintenance	7,121	8,020
Depreciation and amortization	7,546	5,959
General and administrative	4,634	3,405
Taxes, other than income taxes	1,777	2,053
Total Operating Costs and Expenses	49,962	48,872
Operating Income	10,296	17,657
Other Income (Expense):		
Interest (expense) income, net	(5,564)	
Other income (expense), net	339	(421)
Total Other Income (Expense)	(5,225)	(421)
Income Before Income Taxes	5,071	17,236
Texas Margin Taxes		89
Net Income to Member	$ 5,071	$ 17,147

The accompanying notes are an integral part of these combined financial statements.

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TALLGRASS ENERGY PARTNERS PREDECESSOR

AND TALLGRASS ENERGY PARTNERS PRE-PREDECESSOR

CONDENSED COMBINED STATEMENTS OF COMPREHENSIVE INCOME

(UNAUDITED)

	TEP Predecessor Three Months Ended March 31, 2013 (in thousands)	TEP Pre-Predecessor Three Months Ended March 31, 2012 (in thousands)
Net Income to Member	$ 5,071	$ 17,147
Other Comprehensive Income:		
Reclassification of change in fair value of derivatives to net income		103
Change in fair value of derivatives utilized for hedging purposes		2,038
Total Other Comprehensive Income		2,141
Comprehensive Income	$ 5,071	$ 19,288

The accompanying notes are an integral part of these combined financial statements.

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TALLGRASS ENERGY PARTNERS PREDECESSOR

CONDENSED COMBINED BALANCE SHEETS

(UNAUDITED)

	TEP Predecessor	
	March 31, 2013	December 31, 2012
	(in thousands)	
ASSETS		
Current Assets:		
Accounts receivable, net	$ 26,507	$ 17,848
Accounts receivable from related parties		6,463
Gas imbalances	1,072	1,282
Inventories	4,665	2,204
Derivative assets at fair value		224
Prepayments and other current assets	244	47
Total Current Assets	32,488	28,068
Property, plant and equipment, net	663,239	669,476
Goodwill	304,916	301,852
Deferred financing costs allocated from TD	12,585	13,352
Other deferred charges	20,774	23,066
Total Assets	$ 1,034,002	$ 1,035,814
LIABILITIES AND MEMBER S EQUITY		
Current Liabilities:		
Accounts payable	$ 44,867	$ 35,496
Notes payable to related parties		1,387
Gas imbalances	1,347	1,250
Derivative liabilities at fair value	717	23
Accrued taxes	4,942	3,465
Current portion of long-term debt allocated from TD	4,000	4,000
Accrued other current liabilities	32,966	26,233
Total Current Liabilities	88,839	71,854
Long-term debt allocated from TD	389,715	390,491
Other long-term liabilities and deferred credits	1,627	1,635
Total Long-term Liabilities	391,342	392,126
Commitments and Contingencies (Note 11)		
Member s Equity:		
Member s Capital	553,821	571,834
Total Member s Equity	553,821	571,834
Total Liabilities and Member s Equity	$ 1,034,002	$ 1,035,814

The accompanying notes are an integral part of these combined financial statements.

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TALLGRASS ENERGY PARTNERS PREDECESSOR

AND TALLGRASS ENERGY PARTNERS PRE-PREDECESSOR

CONDENSED COMBINED STATEMENTS OF CASH FLOWS

(UNAUDITED)

	TEP Predecessor Three Months Ended March 31, 2013 (in thousands)	TEP Pre-Predecessor Three Months Ended March 31, 2012 (in thousands)
Cash Flows from Operating Activities:		
Net income to Member	$ 5,071	$ 17,147
Adjustments to reconcile net income to net cash flows from operating activities:		
Depreciation and amortization	8,297	5,930
Noncash change in fair value of derivative financial instruments	919	
Changes in components of working capital:		
Accounts receivable	(565)	4,094
Gas imbalances	307	3,182
Inventories	(2,181)	(237)
Accounts payable and accrued liabilities	20,066	(234)
Regulatory assets	(126)	(16)
Other, net	233	2,585
Net Cash Provided by Operating Activities	32,021	32,451
Cash Flows from Investing Activities:		
Capital expenditures	(8,943)	(532)
Net cash paid for purchase and sale of gas in underground storage		(5,153)
Disposal of property, plant and equipment (net of removal costs)	6	(11)
Net Cash Used in Investing Activities	(8,937)	(5,696)
Cash Flows from Financing Activities:		
Distributions to Member, net	(23,084)	(26,755)
Net Cash Used in Financing Activities	(23,084)	(26,755)
Net Change in Cash and Cash Equivalents		
Cash and Cash Equivalents, beginning of period		
Cash and Cash Equivalents, end of period	$	$

The accompanying notes are an integral part of these combined financial statements.

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TALLGRASS ENERGY PARTNERS PREDECESSOR

AND TALLGRASS ENERGY PARTNERS PRE-PREDECESSOR

CONDENSED COMBINED STATEMENTS OF MEMBER S EQUITY

(UNAUDITED)

	TEP Pre-Predecessor Member s Capital	TEP Predecessor Member s Capital	Accumulated Other Comprehensive Income	Total Member s Equity
		(in thousands)		
Member s Equity at January 1, 2012	$ 733,717	$	$ 3,091	$ 736,808
Net income to Member	17,147			17,147
Distributions to Member, net	(26,755)			(26,755)
Total change in fair value of derivatives, including a reclassification to earnings			2,141	2,141
Member s Equity at March 31, 2012	$ 724,109	$	$ 5,232	$ 729,341
Member s Equity at January 1, 2013	$	$ 571,834	$	$ 571,834
Net income to Member		5,071		5,071
Distributions to Member, net		(23,084)		(23,084)
Member s Equity at March 31, 2013	$	$ 553,821	$	$ 553,821

The accompanying notes are an integral part of these combined financial statements.

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TALLGRASS ENERGY PARTNERS PREDECESSOR

AND TALLGRASS ENERGY PARTNERS PRE-PREDECESSOR

NOTES TO CONDENSED COMBINED FINANCIAL STATEMENTS

(UNAUDITED)

1. Description of Business

The term Predecessor Entities refers to both Tallgrass Energy Partners Predecessor (TEP Predecessor) and Tallgrass Energy Partners Pre-Predecessor (TEP Pre-Predecessor), which are comprised of the businesses described below that were owned by Kinder Morgan Energy Partners, LP (KMP) prior to November 13, 2012. On November 13, 2012, KMP sold those assets, among others, to Tallgrass Development, LP (TD) for approximately $1.8 billion in cash and approximately $1.5 billion in assumed debt.

The Predecessor Entities are referred to as TEP Predecessor for the period in which they were owned by TD, beginning November 13, 2012, and as TEP Pre-Predecessor for periods in which they were owned by KMP, prior to November 13, 2012.

The businesses included in the Predecessor Entities consist of:

- Tallgrass Interstate Gas Transmission LLC (TIGT), an interstate gas pipeline and storage system that is regulated by the Federal Energy Regulatory Commission (FERC). TIGT currently has approximately 5,250 miles of varying diameter natural gas transmission lines in Colorado, Kansas, Missouri, Nebraska and Wyoming. Upon receipt of FERC approval and completion of construction of certain gas facilities necessary to maintain existing natural gas service, TIGT will sell approximately 430 miles of natural gas pipeline, along with the associated rights of way and certain other equipment, to a subsidiary of TD. For more information, see Note 11 *Regulatory Matters*.

- Tallgrass Midstream LLC (TMID) is a Delaware limited liability company that owns and operates one treating and two processing plants in Wyoming.

Prior to the sale of these assets to TD on November 13, 2012, TIGT was named Kinder Morgan Interstate Gas Transmission LLC and TMID was named Kinder Morgan Upstream LLC.

For additional information regarding the acquisition of TIGT and TMID, see Note 3 *Business Combinations*.

On May 17, 2013, Tallgrass Energy Partners, LP (TEP) completed an initial public offering (the Offering) of TEP common units. On that date, TD contributed its ownership interest in TIGT and TMID to TEP. For additional information see Note 13 *Subsequent Events*.

2. Summary of Significant Accounting Policies

Basis of Presentation

These unaudited condensed combined financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America (GAAP) for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. The year-end balance sheet data was derived from audited financial statements but does not include disclosures required by GAAP for annual periods. The unaudited condensed combined financial statements for the three months ended March 31, 2013 and 2012 include all normal, recurring adjustments and disclosures that we believe are necessary for a fair presentation of the results for the interim periods. In this report, the Financial Accounting Standards Board is referred to as the FASB and the FASB Accounting Standards Codification is referred to as the Codification or ASC.

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Our financial results for the three months ended March 31, 2013 are not necessarily indicative of the results that may be expected for the full year ending December 31, 2013. These unaudited condensed combined financial statements should be read in conjunction with our combined financial statements and notes thereto included in our final prospectus dated May 13, 2013 (the Prospectus) and filed with the Securities Exchange Commission (the SEC) pursuant to Rule 424 on May 14, 2013.

The condensed combined financial statements of the Predecessor Entities include legal entities, as detailed above, that are indirect wholly-owned subsidiaries of the Predecessor Entities. As the condensed combined financial statements reflect TEP Predecessor and TEP Pre-Predecessor as single entities, significant intra-entity items have been eliminated in the presentation. Net equity distributions of the Predecessor Entities included in the Condensed Combined Statements of Equity and Condensed Combined Statements of Cash Flows represent transfers of cash as a result of TD and KMP s centralized cash management systems, under which cash balances are swept daily and recorded as loans from the subsidiaries to TD. These loans are then periodically recorded as equity distributions.

The accompanying condensed combined financial statements for TEP Predecessor for the three months ended March 31, 2013 and for TEP Pre-Predecessor for the three months ended March 31, 2012, are presented on a held in use basis. The condensed combined financial statements were prepared in contemplation of the Predecessor Entities being contributed by TD to Tallgrass Energy Partners, LP (TEP), an entity formed on February 6, 2013 that completed an initial public offering of common units representing limited partner interests on May 17, 2013. TD s conveyance of TIGT and TMID to TEP will be accounted for as a transfer of businesses between entities under common control in accordance with ASC 805. The condensed combined financial statements for TEP Predecessor for the three months ended March 31, 2013 reflect certain purchase accounting adjustments pursuant to the acquisition of TIGT and TMID as discussed in Note 1 *Description of Business* and Note 3 *Business Combinations*. TEP Predecessor s financial results as presented on the condensed combined statements of income, comprehensive income and cash flows have been separated from TEP Pre-Predecessor s financial results by a bold vertical black line.

Use of Estimates

Certain amounts included in or affecting these condensed combined financial statements and related disclosures must be estimated, requiring management to make certain assumptions with respect to values or conditions which cannot be known with certainty at the time the financial statements are prepared. These estimates and assumptions affect the amounts reported for assets, liabilities, revenues, and expenses during the reporting period, and the disclosure of contingent assets and liabilities at the date of the financial statements. Management evaluates these estimates on an ongoing basis, utilizing historical experience, consultation with experts and other methods it considers reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from these estimates. Any effects on the Predecessor Entities business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

New Accounting Pronouncements Adopted

ASU No. 2011-11, Balance Sheet (Topic 210), Disclosures about Offsetting Assets and Liabilities and ASU No. 2013-01, Balance Sheet (Topic 210), Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities

On December 16, 2011, the FASB issued ASU No. 2011-11, Balance Sheet (Topic 210), *Disclosures about Offsetting Assets and Liabilities* . ASU 2011-11 requires entities to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. In January 2013, the FASB issued ASU No. 2013-01, Balance Sheet (Topic 210), *Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities,* which clarifies that the scope of

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ASU No. 2011-11 applies to derivatives accounted for in accordance with the Codification guidance for derivatives and hedging transactions, including bifurcated embedded derivatives, repurchase agreements and reverse purchase agreements, and certain securities borrowing and securities lending transactions. Entities are required to apply the amendments of ASU No. 2011-11 for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. All disclosures provided by those amendments are required to be provided retrospectively for all comparative periods presented. The adoption of ASU 2011-11 on January 1, 2013 did not have a material impact on the financial statements of the Predecessor Entities.

ASU No. 2013-02, Comprehensive Income (Topic 220), Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income

In February 2013, the FASB issued ASU No. 2013-02, Comprehensive Income (Topic 220), *Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income*. ASU 2013-02 does not change the current requirements for reporting net income or other comprehensive income in financial statements. However, the amendments require an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component, either on the face of the statement where net income is presented or in the notes, depending on whether or not the amount reclassified is required under GAAP to be reclassified to net income in its entirety in the same reporting period. ASU 2013-02 is effective for public entities prospectively for reporting periods beginning after December 15, 2012, or January 1, 2013 for TEP Predecessor. The adoption of ASU 2013-02 did not have a material impact on the financial statements of the Predecessor Entities.

3. Business Combinations

On November 13, 2012, TD completed the acquisition of certain assets from KMP for approximately $1.8 billion in cash and approximately $1.5 billion of assumed debt, including a 100% equity interest in both TIGT and TMID, as discussed in Note 1 *Description of Business*. Of the approximately $1.8 billion in cash paid to acquire the net assets, $573.2 million was allocated to TIGT and TMID. The contribution of assets and liabilities from TD to TEP, which was effective on May 17, 2013, will be accounted for as a transaction between entities under common control under ASC 805.

At December 31, 2012, the assets acquired and liabilities assumed in the acquisition were recorded at provisional amounts based on the preliminary purchase price allocation. TD is in the process of obtaining additional information to identify and measure all assets acquired and liabilities assumed in the acquisition within the measurement period. Such provisional amounts will be retrospectively adjusted to reflect any new information about facts and circumstances that existed at the acquisition date that, if known, would have affected the measurement of these amounts.

During the three months ended March 31, 2013, the preliminary purchase price allocation was adjusted for certain immaterial items related to regulatory assets and accrued liabilities. As the changes were not considered material to TEP Predecessor or the purchase price allocation, the adjustments are not retrospectively reflected in the accompanying condensed combined balance sheet as of December 31, 2012.

Prior to May 17, 2013, a portion of the long-term debt held by TD was guaranteed by TIGT and TMID and expected to be assumed by TEP, and was therefore allocated to TIGT and TMID along with the related deferred financing costs at November 13, 2012. For additional information regarding long-term debt, see Note 8 *Long-term Debt*. On May 17, 2013, in connection with the closing of the initial public offering of TEP common units, a portion of the long-term debt held by TD was assumed and repaid by TEP. TIGT and TMID were also released as guarantors of the TD debt and became guarantors of the TEP revolving credit facility. For additional information, see Note 13 *Subsequent Events*.

The goodwill recorded in the condensed combined balance sheets is expected to be deductible for tax purposes. Of the $304.9 million of goodwill at March 31, 2013, $78.0 million was assigned to the Processing

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segment and $226.9 million was assigned to the Gas Transportation and Storage segment. The goodwill is primarily attributable to (i) the strategic location of the assets, including access to key supply sources and major customer demand markets; (ii) the complementary location of the assets relative to each other and relative to key market areas; (iii) growth opportunities through production growth requiring processing in the Rockies; (iv) future pipeline interconnects and fertilizer and power plant conversions that may potentially provide volume growth opportunities; and (v) a trained workforce.

The following unaudited pro forma financial information for the historical periods are presented as if the acquisition of TIGT and TMID had been completed on January 1, 2012. The pro forma financial information is not necessarily indicative of what the actual results of operations or financial position of TEP Predecessor would have been if the transactions had in fact occurred on the date or for the period indicated, nor do they purport to project the results of operations or financial position of KMP for any future periods or as of any date. The pro forma financial information does not give effect to any cost savings, operating synergies, or revenue enhancements expected to result from the transactions or the costs to achieve these cost savings, operating synergies, and revenue enhancements.

	TEP Predecessor	TEP Pre-Predecessor
	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
	(in thousands)	(in thousands)
Revenue	$ 60,258	$ 66,529
Net income	$ 5,071	$ 9,779

The pro forma revenue and net income includes adjustments for the three months ended March 31, 2012 to give effect to the following:

(a) Reduction in net income to reflect additional depreciation expense associated with the increase in the cost of property, plant and equipment resulting from the allocation of the purchase price to the fair value of the assets and liabilities acquired.

(b) Reduction in net income to reflect interest expense on the long-term debt allocated to TIGT and TMID in connection with the acquisition of TIGT and TMID by TD.

4. Related Party Transactions

The Predecessor Entities have no employees. KMP historically provided and charged TEP Pre-Predecessor for all direct and indirect costs of services provided to us or incurred on our behalf including employee labor costs, information technology services, employee health and life benefits, and all other expenses necessary or appropriate to the conduct of our business. Beginning November 13, 2012, TD provided and charged TEP Predecessor for similar direct and indirect costs of services. The Predecessor Entities record these costs on the accrual basis in the period in which KMP (or TD, beginning November 13, 2012) incurs them. Each of the wholly-owned companies within the Predecessor Entities have agency arrangements with KMP or its affiliates (prior to November 13, 2012) and TD (beginning November 13, 2012) under which KMP, or its contractually obligated affiliate, or TD, as applicable, pay costs and expenses incurred by the Predecessor Entities, act as agents for the Predecessor Entities, and are reimbursed by the Predecessor Entities for such payments. While the substance of the operating agreement remains the same, the cost structure under new management has changed, which affected the basis of certain allocations when the agreements transitioned from KMP to TD.

On May 17, 2013, in connection with the closing of the initial public offering of common units of TEP, TEP and its subsidiaries entered into an Omnibus Agreement with TD and certain of its affiliates. The Omnibus Agreement provides that, among other things, TEP will reimburse TD and its affiliates for all expenses they incur and payments they make on our behalf, including the costs of employee and director compensation and benefits

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as well as the cost of the provision of certain centralized corporate functions performed by TD, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology and human resources in each case to the extent reasonably allocable to TEP.

For the calendar year 2013, TEP s annual cost reimbursements to TD for costs discussed above, are expected to be $18.5 million. Effective May 17, 2013, TEP will also pay a quarterly reimbursement to TD for costs associated with being a public company. The quarterly public company reimbursement amount is expected to be $625,000. These reimbursement amounts will be periodically reviewed and adjusted as necessary to continue to reflect reasonable allocation of costs to TEP. For additional information, see Note 13 *Subsequent Events*.

Due to the cash management agreements discussed in Note 2 *Summary of Significant Accounting Policies*, intercompany balances between the Predecessor Entities are periodically settled and treated as distributions.

Totals of transactions with affiliated companies are as follows:

	TEP Predecessor Three Months Ended March 31, 2013 (in thousands)	TEP Pre-Predecessor Three Months Ended March 31, 2012 (in thousands)
Cost of sales and transportation services	$ (144)[(1)]	$ 3,112[(1)]
Charges from the Predecessor Entities: [(2)]		
Property, plant and equipment, net	$ 4,709	$ 652
Other deferred charges	$ 1,038	$ 10
Operation and maintenance	$ 3,586	$ 3,280
General and administrative	$ 4,634[(3)]	$ 2,938

(1) The Predecessor Entities have certain transactions with related parties in which activity relating to gas imbalance payables and receivables are recorded as Cost of sales and transportation services. For the three months ended March 31, 2013, gas imbalance payables to related parties decreased, resulting in negative cost of sales for those periods.

(2) Charges from the Predecessor Entities include directly charged wages and salaries, other compensation and benefits, and shared services.

(3) During the three months ended March 31, 2013, TEP Predecessor reimbursed TD for general and administrative expenses pursuant to the Omnibus agreement discussed above, resulting in a single allocated amount for general and administrative costs rather than individual charges as in prior periods.

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Details of balances with affiliates included in Accounts receivable and Accounts payable in the Condensed Combined Balance Sheets are as follows:

	March 31, 2013	TEP Predecessor December 31, 2012
	(in thousands)	
Accounts receivable from affiliated companies:		
Tallgrass Operations, LLC	$	$ 6,244
Rockies Express Pipeline LLC		219
Total accounts receivable from associated companies	$	$ 6,463
Payables to affiliated companies:		
Note payable to TD	$	$ 1,381
Interest payable to TD		6
Accounts payable to Rockies Express Pipeline LLC	1	
Total payables to associated companies	$ 1	$ 1,387

As of March 31, 2013 and December 31, 2012, TEP Predecessor had $0.7 million and $0.3 million, respectively, in gas imbalance payables with affiliated entities.

5. Inventory

The components of inventory at March 31, 2013 and December 31, 2012 consisted of the following:

	March 31, 2013	TEP Predecessor December 31, 2012
	(in thousands)	
Materials and supplies	$ 1,573	$ 1,567
Natural gas liquids	864	637
Gas in underground storage	2,228	
Total inventory	$ 4,665	$ 2,204

6. Property, Plant and Equipment

The components of property, plant and equipment at March 31, 2013 and December 31, 2012 consisted of the following:

	March 31, 2013	TEP Predecessor December 31, 2012
	(in thousands)	
Natural gas pipelines	$ 421,716	$ 421,644
Processing and treating assets	195,108	195,108
Buildings	15,518	15,518
Vehicles	3,208	3,138
Gas in underground storage	2,066	2,345

Land	1,534	1,534
General and other	1,207	1,207
Construction work in progress	34,220	32,932
Accumulated depreciation and amortization	(11,338)	(3,950)
Total property, plant and equipment, net	$ 663,239	$ 669,476

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7. Risk Management

The Predecessor Entities enter into derivative contracts with third parties for the purpose of hedging exposures that accompany its normal business activities. The Predecessor Entities normal business activities expose it to risks associated with changes in the market price of natural gas, among other commodities. Specifically, the risks associated with changes in the market price of natural gas, include, among others (i) pre-existing or anticipated physical natural gas sales, (ii) natural gas purchases and (iii) natural gas system use and storage. Prior to November 13, 2012, TEP Pre-Predecessor applied hedge accounting to these derivative contracts. As discussed below, TEP Predecessor elected not to apply hedge accounting.

Beginning on November 13, 2012, all previously hedge-designated derivative contracts were de-designated and changes in the fair value of all derivative contracts are now recorded in earnings in the period in which the change occurs. Accumulated other comprehensive income associated with the derivative contracts was immaterial as of the de-designation date and was eliminated in purchase accounting.

During the three months ended March 31, 2012, TEP Pre-Predecessor recognized no gain or loss on derivatives associated with the ineffectiveness of these hedges and did not exclude any component of the derivative contracts gain or loss from the assessment of hedge effectiveness. Under hedge accounting, as the hedged sales and purchases took place and TEP Pre-Predecessor recorded them into earnings in the same period, TEP Pre-Predecessor also reclassified the associated gains and losses included in accumulated other comprehensive income into earnings. During the three months ended March 31, 2012, no gain or loss was reclassified into earnings as a result of the discontinuance of cash flow hedges due to a determination that the forecasted transactions would no longer occur by the end of the originally specified time period.

Fair Value of Derivative Contracts

The following table summarizes the fair values of the Predecessor Entities derivative contracts included in the accompanying Condensed Combined Balance Sheets:

	Balance Sheet Location	March 31, 2013	December 31, 2012
		(in thousands)	
Energy commodity derivative contracts	Current assets	$	$ 224
Total derivative assets		$	$ 224

	Balance Sheet Location	March 31, 2013	December 31, 2012
		(in thousands)	
Energy commodity derivative contracts	Current liabilities	$ 717	$ 23
Total derivative liabilities		$ 717	$ 23

As of March 31, 2013, the fair value shown for commodity contracts was comprised of derivative volumes totaling 1.7 Bcf of both fixed-price swaps and basis swaps.

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Effect of Derivative Contracts on the Income Statement

The following tables summarize the impact of the Predecessor Entities derivative contracts included in the accompanying Condensed Combined Statements of Income for the three months ended March 31, 2013 and 2012:

	Amount of gain/(loss) recognized in OCI on derivatives (effective portion)	
	TEP Predecessor Three Months Ended March 31, 2013 (in thousands)	TEP Pre-Predecessor Three Months Ended March 31, 2012 (in thousands)
Derivatives in cash flow hedging relationships:		
Energy commodity derivative contracts	$	$ 2,038

	Location of gain/(loss) reclassified from AOCI into income (effective portion)	**Amount of gain/(loss) reclassified from Accumulated OCI into income (effective portion)**	
		TEP Predecessor Three Months Ended March 31, 2013 (in thousands)	TEP Pre-Predecessor Three Months Ended March 31, 2012 (in thousands)
Derivatives in cash flow hedging relationships:			
Energy commodity derivative contracts	Natural gas sales	$	$ 103

	Location of gain/(loss) recognized in income on derivative	**Amount of gain/(loss) recognized in income on derivatives**	
		TEP Predecessor Three Months Ended March 31, 2013 (in thousands)	TEP Pre-Predecessor Three Months Ended March 31, 2012 (in thousands)
Derivatives not designated as hedging contracts:			
Energy commodity derivative contracts	Natural gas sales	$ (919)	$

Credit Risk

The Predecessor Entities have counterparty credit risk as a result of their use of financial derivative contracts. The Predecessor Entities counterparties consist of major financial institutions. This concentration of counterparties may impact the Predecessor Entities overall exposure to credit risk, either positively or negatively in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

The Predecessor Entities maintain credit policies with regard to their counterparties that it believes minimize its overall credit risk. These policies include (i) an evaluation of potential counterparties financial condition (including credit ratings), (ii) collateral requirements under certain circumstances and (iii) the use of standardized agreements which allow for netting of positive and negative exposure associated with a single counterparty. Based on its policies and exposure, the Predecessor Entities management does not anticipate a material adverse effect on their financial position, results of operations, or cash flows as a result of counterparty performance.

The Predecessor Entities over-the-counter swaps are entered into with counterparties outside central trading organizations such as a futures, options or stock exchange. These contracts are with financial institutions with investment grade credit ratings. While the Predecessor Entities enter into derivative transactions principally with investment grade counterparties and actively monitors their ratings, it is nevertheless possible that from time to time losses will result from counterparty credit risk in the future. As of March 31, 2013, the fair value of TIGT s derivative contracts was a liability, resulting in no credit exposure from our counterparty as of that date.

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In addition, in conjunction with the purchase of exchange-traded derivative contracts, or when the market value of the Predecessor Entities derivative contracts with specific counterparties exceeds established limits, the Predecessor Entities are required to provide collateral to their counterparties, which may include posting letters of credit or placing cash in margin accounts. As of March 31, 2013 and December 31, 2012, TEP Predecessor did not have any outstanding letters of credit in support of its hedging of commodity price risks associated with the sale of natural gas. As of March 31, 2013 and December 31, 2012, TEP Predecessor had no margin deposits with counterparties associated with energy commodity contract positions. The Predecessor Entities also have agreements with certain counterparties to its derivative contracts that contain provisions requiring it to post additional collateral upon a decrease in its credit rating. As of March 31, 2013, TEP Predecessor had no derivative instruments with credit-risk-related contingent features in a net liability position and would not have to post additional collateral if a downgrade was triggered.

Fair Value

Derivative assets and liabilities are measured and reported at fair value. Derivative contracts can be exchange-traded or over-the-counter (OTC). Exchange-traded derivative contracts typically fall within Level 1 of the fair value hierarchy if they are traded in an active market. The Predecessor Entities value exchange-traded derivative contracts using quoted market prices for identical securities.

OTC derivatives are valued using models utilizing a variety of inputs including contractual terms; commodity and interest rate curves; and measures of volatility. The selection of a particular model and particular inputs to value an OTC derivative contract depends upon the contractual terms of the instrument as well as the availability of pricing information in the market. The Predecessor Entities use similar models to value similar instruments. For OTC derivative contracts that trade in liquid markets, such as generic forwards and swaps, model inputs can generally be verified and model selection does not involve significant management judgment. Such contracts are typically classified within Level 2 of the fair value hierarchy.

Certain OTC derivative contracts trade in less liquid markets with limited pricing information, and the determination of fair value for these derivative contracts is inherently more difficult. Such contracts are classified within Level 3 of the fair value hierarchy. The valuations of these less liquid OTC derivatives are typically impacted by Level 1 and/or Level 2 inputs that can be observed in the market, as well as unobservable Level 3 inputs. Use of a different valuation model or different valuation input values could produce a significantly different estimate of fair value. However, derivative contracts valued using inputs unobservable in active markets are generally not material to the Predecessor Entities financial statements.

When appropriate, valuations are adjusted for various factors including credit considerations. Such adjustments are generally based on available market evidence. In the absence of such evidence, management s best estimate is used.

The following tables summarize the fair value measurements of the Predecessor Entities energy commodity derivative contracts as of March 31, 2013 and December 31, 2012 based on the fair value hierarchy established by the Codification:

		Asset fair value measurements using		
	Total	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
		(in thousands)		
TEP Predecessor as of March 31, 2013				
Energy commodity derivative contracts	$	$	$	$
TEP Predecessor as of December 31, 2012				
Energy commodity derivative contracts	$ 224	$	$ 224	$

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	Total	Liability fair value measurements using Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
		(in thousands)		
TEP Predecessor as of March 31, 2013				
Energy commodity derivative contracts	$ 717	$	$ 717	$
TEP Predecessor as of December 31, 2012				
Energy commodity derivative contracts	$ 23	$	$ 23	$

The table below provides a summary of changes in the fair value of the Predecessor Entities significant unobservable inputs (Level 3) energy commodity derivative contracts:

	TEP Predecessor Three Months Ended March 31, 2013 (in thousands)	TEP Pre-Predecessor Three Months Ended March 31, 2012 (in thousands)
Derivatives net asset (liability):		
Beginning of period	$	$ (352)
Total gains or (losses)		
Included in other comprehensive income		79
Settlements		(10)
End of period	$	$ (283)
The amount of total gains or losses for the period included in earnings attributable to the change in unrealized gains or losses relating to assets held at the reporting date	$	$

8. Long-term Debt

On November 13, 2012, TD entered into a credit agreement with a syndicate of lenders which included a term loan, a delayed draw term loan and a revolving credit facility. As of March 31, 2013, only the term loan had been drawn. The term loan matures on November 13, 2018 and bears interest at a variable rate equal to a reserve adjusted Eurodollar rate + 4.00%, subject to a LIBOR floor of 1.25%, or an alternate base rate + 3.00%. During the three months ended March 31, 2013, TD elected the reserve adjusted Eurodollar rate + 4.00% rate, however, on April 30, 2013 the $400 million of the term loan allocated to TEP was converted to the alternate base rate + 3.00%. As discussed in Note 3 *Business Combinations*, $400 million of the term loan, along with the corresponding discount and deferred financing costs, was allocated to TEP Predecessor on November 13, 2012. The term loan is an obligation of TD and prior to May 17, 2013, was guaranteed by TIGT and TMID.

Upon the closing of the TEP initial public offering on May 17, 2013, TEP legally assumed the previously allocated $400 million portion of the term loan and used a portion of the initial public offering proceeds, along with borrowings under TEP s new $500 million credit agreement effective May 17, 2013, to repay its $400 million portion of the term loan, at which time TIGT and TMID were released as guarantors of the TD debt. For additional information see Note 13 *Subsequent Events*.

The following table sets forth the carrying amount and fair value of the long-term debt allocated from TD, which is not measured at fair value in the Condensed Combined Balance Sheets as of March 31, 2013 and December 31, 2012, but for which fair value is disclosed:

	Fair Value				
	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)	Total	Carrying Amount
	(in thousands)				
March 31, 2013	$	$ 407,479	$	$ 407,479	$ 393,715
December 31, 2012	$	$ 404,000	$	$ 404,000	$ 394,491

The term loan allocated from TD was carried at amortized cost. The fair value of the debt was estimated based on quoted market prices. TEP Predecessor is not aware of any factors that would significantly affect the estimated fair value since March 31, 2013. As described above, this debt was retired in connection with TEP s initial public offering on May 17, 2013.

9. Member s Equity

As discussed in Note 1 *Description of Business*, TEP Predecessor completed the acquisition of TEP Pre-Predecessor subsidiary entities on November 13, 2012. During the three months ended March 31, 2013, there were no material changes in TEP Pre-Predecessor s ownership interests in its subsidiaries. On May 17, 2013, in conjunction with the closing of TEP s initial public offering, TD s ownership interest in TIGT and TMID was contributed to TEP. For additional information, see Note 13 *Subsequent Events*.

Distributions and Contributions

As discussed in Note 2 *Summary of Significant Accounting Policies*, the net amount of transfers for loans made each day through the centralized cash management system, less reimbursement payments under the agency agreement described in Note 4 *Related Party Transactions*, is recognized periodically as equity distributions or contributions. Net distributions to TEP Predecessor members for the three months ended March 31, 2013 were $23.1 million. Net distributions to TEP Pre-Predecessor members for the three months ended March 31, 2012 were $26.8 million.

10. Reporting Segments

Our operations are located in the United States and are organized into two reporting segments: (1) Gas Transportation and Storage, and (2) Processing.

Gas Transportation and Storage

The Predecessor Entities Gas Transportation and Storage segment is engaged in ownership and operation of interstate natural gas pipelines and related natural gas storage facilities that provide services to third-party natural gas distribution utilities and other shippers.

Processing

The Predecessor Entities Processing segment is engaged in ownership and operation of natural gas processing and treating facilities that produce natural gas liquids and residue gas that is sold in local wholesale markets or delivered into pipelines for transportation to additional end markets.

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These segments are monitored separately by management for performance and are consistent with internal financial reporting. These segments have been identified based on the differing products and services, regulatory environment and the expertise required for these operations.

The following tables set forth the Predecessor Entities segment information for the periods indicated:

TEP Predecessor for three months ended March 31, 2013	Gas Transportation and Storage	Processing	Eliminations	Total
	(in thousands)			
Revenues from external customers	$ 23,426	36,832	$	$ 60,258
Inter-segment revenues	171		(171)	
Total revenues	23,597	36,832	(171)	60,258
Operating costs and expenses	12,589	29,998	(171)	42,416
Depreciation and amortization	5,927	1,619		7,546
Total operating costs and expenses	18,516	31,617	(171)	49,962
Operating income	5,081	5,215		10,296
Interest expense, net	(3,884)	(1,680)		(5,564)
Other income (expense)	339			339
Net income	$ 1,536	$ 3,535	$	$ 5,071
Total assets	$ 726,814	$ 307,188	$	$ 1,034,002

TEP Pre-Predecessor for three months ended March 31, 2012	Gas Transportation and Storage	Processing	Eliminations	Total
	(in thousands)			
Revenues from external customers	$ 28,392	$ 38,137	$	$ 66,529
Inter-segment revenues	206		(206)	
Total revenues	28,598	38,137	(206)	66,529
Operating costs and expenses	12,337	30,782	(206)	42,913
Depreciation and amortization	5,179	780		5,959
Total operating costs and expenses	17,516	31,562	(206)	48,872
Operating income	11,082	6,575		17,657
Interest income, net				
Other income (expense)	(421)			(421)
Texas Margin Taxes	(66)	(23)		(89)
Net income	$ 10,595	$ 6,552	$	$ 17,147
Total assets	$ 685,865	$ 80,232	$	$ 766,097

11. Regulatory Matters

TIGT

Pony Express Pipeline Conversion Project FERC Docket CP12-495

On August 6, 2012, TIGT filed an application to: (1) abandon for FERC purposes approximately 430 miles of mainline natural gas pipeline facilities, along with associated rights of way and other related equipment (collectively, the Pony Express Assets), and the natural gas service therefrom by transfer to an affiliate, Tallgrass Pony Express Pipeline, LLC, for the purpose of converting the facilities into crude oil pipeline facilities; and (2) construct and operate certain replacement-type facilities necessary to continue service to existing natural gas firm transportation customers following the proposed conversion. The FERC abandonment does not constitute an abandonment for accounting purposes.

This application upon FERC approval and implementation will re-deploy existing pipeline assets to meet the growing market need to transport oil supplies from the Bakken Shale while, at the same time continuing to operate TIGT s natural gas transportation facilities to meet all current and expected needs of its natural gas customers. Such application, upon approval by the FERC, will authorize the reconversion of a portion of the Pony Express Pipeline back to the transportation of crude oil as it was prior to 1997. On May 14, 2013, the FERC issued a notice scheduling June 14, 2013 as the date for publication of its environmental assessment on the project. The environmental assessment issued on June 14, 2013 concludes that the project would not constitute a major federal action significantly affecting the quality of the human environment and recommends that the order contain a finding of no significant impact.

12. Legal and Environmental Matters

Legal

Other than the matters discussed below, the Predecessor Entities are defendants in various lawsuits arising from the day-to-day operations of their business. Although no assurance can be given, the Predecessor Entities believe, based on their experiences to date, that the ultimate resolution of such routine items will not have a material adverse impact on its business, financial position, results of operations or cash flows.

TEP Predecessor accrues for litigation and claims when it is probable that a liability has been incurred and the amount of loss can be reasonably estimated. TEP Predecessor has evaluated claims in accordance with the accounting guidance for contingencies that it deems both probable and reasonably estimable and, accordingly, has recorded aggregate reserves for all claims of approximately $1.1 million and $0.1 million as of March 31, 2013 and December 31, 2012, respectively. These reserves are reported on the accompanying Condensed Combined Balance Sheets within other accrued liabilities.

TMID

West Frenchie Draw

TMID has been a party to the following legal actions pertaining to its West Frenchie Draw treating plant:

Elkhorn Construction, Inc. v. KM Upstream LLC and Newpoint Gas Services, Inc., Civil Action No. 36823 in the District Court of Fremont County, Wyoming (9th Judicial District)(the Trial Court Action); *Elkhorn Construction, Inc. v. KM Upstream LLC*, Appeal No. S-11-0186 and S-11-0208 in the Wyoming Supreme Court (the Appeal); *In Re: Newpoint Gas, L.P.*, Case No. 10-16104 in the U.S. Bankruptcy Court for the Western District of Oklahoma (Oklahoma City)(the Newpoint Bankruptcy).

Elkhorn Construction, Inc., a sub-contractor to Newpoint Gas Services, Inc. (Newpoint Gas Services) filed suit on March 23, 2009 in Fremont County, Wyoming to enforce liens against TMID in the principal amount of approximately $4.9 million plus interest, late charges, attorney s fees and costs from January 16, 2009. Elkhorn s claim arises out of construction costs incurred in building the West Frenchie Draw Amine Plant in Fremont County, Wyoming. On November 24, 2009, Newpoint Gas Services was added to the litigation as a defendant. TMID and Newpoint Gas Services filed cross-claims against each other. Newpoint Gas Services cross-claim against TMID seeks damages in excess of $11.0 million (although it includes Elkhorn s claimed damages of $4.9 million). TMID s cross-claim seeks indemnification from Newpoint Gas Services for any damages awarded to Elkhorn against TMID, as well as the costs of defense. TMID and Newpoint Gas Services have settled all claims and are working on settlement documents, which, when executed will result in a dismissal of parties claims against each other.

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On September 21, 2012, TMID paid the adjudicated portion of Elkhorn s mechanics lien of $4.7 million plus 7% interest from the date of the lien for a total payment of $5.9 million. On April 30, 2013, the Court awarded Elkhorn additional principal and interest (including post-judgment interest) on its mechanic s lien claim. On May 30, 2013, TMID paid $235,993 to satisfy the remaining portion of Elkhorn s mechanic s lien claim. On June 12, 2013, the Court granted Elkhorn s motion for summary judgment seeking enforcement and foreclosure of its oil and gas lien claim, which provides for the recovery of attorney s fees and costs by Elkhorn. Following written requests and responses from the parties, the Court will determine the amount of fees and costs awarded to Elkhorn without further hearing. TMID has submitted a notice of appeal to the court regarding the remaining amount of post-judgment interest awarded by the Court, equal to approximately $189,000, and intends to submit a notice of appeal regarding the oil and gas lien claim.

Newpoint Gas L.P. (Newpoint LP), a closely held affiliate of Newpoint Gas Services, commenced the above-referenced bankruptcy court case under Chapter 7 of the Bankruptcy Code. TMID filed an adversary proceeding in the bankruptcy action seeking to consolidate the assets and liabilities of Newpoint Gas Services with Newpoint LP. The judge issued an order dismissing the adversary proceeding on June 10, 2013 based on a finding that the Trustee was the only party with standing to seek substantive consolidation. TMID filed a proof of claim in the bankruptcy case, but on June 18, 2013, filed a motion to withdraw its claim, conditioned upon a release by the estate of any potential claims against TMID.

ConocoPhillips Off-Spec Product Deliveries

In April and May of 2009, TMID delivered to ConocoPhillips NGL product that was alleged by a ConocoPhillips affiliate to contain fluoride levels that exceeded contract tolerances. In February 2012, TMID paid $1.1 million to settle this issue with the affiliated refinery that received the product from ConocoPhillips. TMID recognized the full settlement amount of $1.1 million in 2009. In 2012, TMID recovered $350,000 from two parties who delivered the contested product to TMID and this matter is now concluded.

TIGT

Cornhusker Energy Lexington Plant Explosion

TIGT is the defendant in a lawsuit pending in state court in Douglas County, Nebraska (CI 10 9387384). Plaintiffs in the suit are Cornhusker Energy Lexington, LLC and its insurer, National Union Fire Insurance Company of Pittsburgh, Pennsylvania. The suit was initiated in February 2010. Plaintiffs allege that Cornhusker received natural gas that was transported on the TIGT System that did not meet required pipeline specifications, and as a result Cornhusker s ethanol plant suffered an explosion and subsequent fire. Plaintiffs complaint requests monetary relief, attorney s fees, costs and interest of approximately $3.9 million; however in connection with mediation in May 2013, Plaintiffs increased the amount of their alleged damages in a statement to the mediator. Although we believe Cornhusker s claims to be without merit, TD has agreed to indemnify TIGT for any settlement of damage award in excess of the $3.9 million, pursuant to an Omnibus Agreement between TD and TEP, among others. A trial date has been set by the Court for November 2013.

Environmental

The Predecessor Entities are subject to a variety of federal, state and local laws that regulate permitted activities relating to air and water quality, waste disposal, and other environmental matters. The Predecessor Entities believe that compliance with these laws will not have a material adverse impact on their business, cash flows, financial position or results of operations. However, there can be no assurances that future events, such as changes in existing laws, the promulgation of new laws, or the development of new facts or conditions will not cause the Predecessor Entities to incur significant costs. TEP Predecessor had recorded environmental accruals of $4.0 million at March 31, 2013 and December 31, 2012.

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TMID

Casper and Douglas Plants, United States Environmental Protection Agency Notice of Violation

In March 2011, the United States Environmental Protection Agency (U.S. EPA) and the Wyoming Department of Environmental Quality (WDEQ) conducted an inspection at the Douglas and Casper Gas Plants in Wyoming. In June 2011, TMID received two letters from the U.S. EPA alleging violations at both gas plants of the Risk Management Program requirements under the Clean Air Act. TMID has executed Combined Complaint and Consent Agreements with the U.S. EPA, including monetary penalties of $158,000 for each facility, to resolve these allegations, which were approved by the U.S. EPA in September 2012.

Casper Plant, U.S. EPA Notice of Violation

In August 2011, the U.S. EPA and the WDEQ conducted an inspection of the Leak Detection and Repair Program at the Casper Gas Plant in Wyoming. In September 2011, TMID received a letter from the U.S. EPA alleging violations of the Standards of Performance of Equipment Leaks for Onshore Natural Gas Processing Plant requirements under the Clean Air Act. In April 2013, TMID received a settlement offer from the U.S. EPA. TMID is working with the U.S. EPA to respond to the settlement offer.

Casper Mystery Bridge Superfund Site

The Casper Gas Plant is part of the Mystery Bridge Road/U.S. Highway 20 Superfund Site also known as Casper Mystery Bridge Superfund Site. Remediation work at the Casper Gas Plant has been completed and the Predecessor Entities have requested that the portion of the site attributable to the Predecessor Entities be delisted from the National Priorities List.

13. Subsequent Events

Initial Public Offering

On May 17, 2013, TEP closed its initial public offering (the Offering) of 14,600,000 common units at a price of $21.50 per unit, which included 1,550,000 of a possible 1,957,500 common units from the partial exercise of the over-allotment option by the underwriters. Proceeds to TEP from the sale of the common units were approximately $295.9 million, net of certain offering costs and underwriters commissions. The Offering represented the sale to the public of an approximately 36% limited partner interest in TEP.

In connection with the Offering, TD contributed 100% of the membership interests in TIGT and TMID to TEP in exchange for (i) 9,700,000 common units and 16,200,000 subordinated units, representing an approximate 64% limited partner interest in TEP in the aggregate, (ii) TEP s assumption of $400 million of indebtedness related to TD s acquisition of TIGT and TMID and (iii) $85.5 million in cash as reimbursement for a portion of the capital expenditures made by TD to purchase the contributed assets. At the closing of the Offering, TEP used the total proceeds of approximately $295.9 million to repay approximately $295.9 million of the debt assumed from TD.

Partnership Agreement

In connection with the Offering, TEP entered into a revised partnership agreement on May 17, 2013. The revised partnership agreement requires TEP to distribute its available cash on a quarterly basis, subject to certain terms and conditions, beginning with the quarter ending June 30, 2013. No distributions were declared for the three months ended March 31, 2013. TEP anticipates declaring a prorated distribution in the second quarter of 2013 for the period from May 17, 2013 to June 30, 2013.

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New Revolving Credit Facility

On May 17, 2013, in connection with the Offering, TEP entered into a $500 million senior secured revolving credit facility with Barclays Bank PLC, as administrative agent, and a syndicate of lenders, which will mature on the fifth anniversary of the closing date of the Offering. On the closing date of the Offering, TEP borrowed $231.0 million under the credit facility, the proceeds of which were used to repay the remaining approximately $104.1 million of debt assumed from TD, a distribution to TD of $31.2 million in net proceeds from the exercise of the underwriter s option to purchase additional Units, $85.5 million to TD as reimbursement for a portion of the capital expenditures made by TD to purchase the contributed assets and the remainder to pay origination fees related to the new revolving credit facility and other fees associated with the Offering, and to fund working capital requirements of TEP. The remaining commitments under the credit facility are available for capital expenditures and permitted acquisitions, to provide for working capital requirements and for other general partnership purposes. The credit facility has an accordion feature that will allow TEP to increase the available revolving borrowings under the credit facility by up to an additional $100 million, subject to TEP s receipt of increased or new commitments from lenders and satisfaction of certain other conditions. In addition, the credit facility includes a sublimit up to $40 million for swing line loans and a sublimit up to $50 million for letters of credit.

TEP s obligations under the credit facility are (i) guaranteed by TEP and each of its existing and subsequently acquired or organized direct or indirect wholly-owned domestic subsidiaries, subject to TEP s ability to designate certain of its subsidiaries as Unrestricted Subsidiaries and (ii) secured by a first priority lien on substantially all of the present and after acquired property owned by TEP and each guarantor (other than real property interests related to TEP s pipelines).

The credit facility contains various covenants and restrictive provisions that, among other things, limits or restricts TEP s ability (as well as the ability of TEP s restricted subsidiaries) to incur or guarantee additional debt, incur certain liens on assets, dispose of assets, make certain distributions, including distributions from available cash, if a default or event of default under the credit agreement then exists or would result therefrom, change the nature of TEP s business, engage in certain mergers or make certain investments and acquisitions, enter into non arms-length transactions with affiliates and designate certain subsidiaries as Unrestricted Subsidiaries, and also requires maintenance of a consolidated leverage ratio of not more than 4.75 to 1.00 (which will be increased to 5.25 to 1.00 for certain measurement periods following the consummation of certain acquisitions) and a consolidated interest coverage ratio of not less than 2.50 to 1.00.

Borrowings under the credit facility bear interest, at TEP s option, at either (a) a base rate, which is a rate equal to the greatest of (i) the prime rate, (ii) the U.S. federal funds rate plus 0.5% and (iii) a one-month reserve adjusted Eurodollar rate plus 1.00%, in each case, plus an applicable margin, or (b) a reserve adjusted Eurodollar rate, plus an applicable margin. Swing line loans bear interest at the base rate plus an applicable margin. For borrowings bearing interest based on the base rate, the applicable margin is initially 1.00%, and for loans bearing interest based on the reserve adjusted Eurodollar rate, the applicable margin is initially 2.00%. After the first full fiscal quarter after the closing date of the Offering, the applicable margin will range from 1.00% to 2.00% for base rate borrowings and 2.00% to 3.00% for reserve adjusted Eurodollar rate borrowings, based upon TEP s total leverage ratio. The unused portion of the credit facility is subject to a commitment fee, which is initially 0.375%, and after the first full fiscal quarter after the closing date of the Offering, is either 0.375% or 0.500%, based on TEP s total leverage ratio.

Long-Term Incentive Plan

Effective May 13, 2013, Tallgrass MLP GP, LLC, the general partner of TEP, adopted a Long-Term Incentive Plan (LTIP) pursuant to which awards in the form of unrestricted units, restricted units, equity participation units, options, unit appreciation rights or distribution equivalent rights may be granted to employees, consultants, and directors of the general partner and its affiliates who perform services for or on behalf of TEP or its affiliates. Vesting and forfeiture requirements are at the discretion of the Compensation Committee at the time of the grant. On June 26, 2013, Tallgrass MLP GP, LLC approved the grant of up to 1.5 million equity participation units under the LTIP.

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TIGT System

On May 4, 2013 and on June 13, 2013, failures occurred on two separate segments of the TIGT pipeline system, in Kimball County, Nebraska and in Goshen County, Wyoming, resulting in releases of natural gas. Both lines were promptly brought back into service and neither failure caused any known injuries, fatalities, fires or evacuations. The costs to repair or replace the damaged sections are not currently believed to be material. The scope and cost of any additional investigation and remediation activities are currently being evaluated.

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

The historical financial statements included in this Quarterly Report reflect the combined results of operations of Tallgrass Interstate Gas Transmission, LLC and Tallgrass Midstream, LLC, which we refer to collectively as our Predecessor. In connection with our initial public offering, on May 17, 2013 Tallgrass Development LP (TD) contributed to us its equity interests in our Predecessor. The following discussion analyzes the financial condition and results of operations of our Predecessor. In certain circumstances and for ease of reading we discuss the financial results of the Predecessor as being our financial results during historic periods, although our Predecessor was owned by Kinder Morgan prior to November 13, 2012 and by Tallgrass Development from November 13, 2012 until May 17, 2013. As used in this Quarterly Report, unless the context otherwise requires, we, us, our, the Partnership and similar terms refer to Tallgrass Energy Partners, LP, together with its consolidated subsidiaries.

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the unaudited condensed combined financial statements and related notes thereto included elsewhere in this Quarterly Report and the audited financial statements and notes thereto and management s discussion and analysis of financial condition and results of operations for the year ended December 31, 2012 included in our final prospectus dated May 13, 2013 (the Prospectus) and filed with the Securities Exchange Commission (the SEC) pursuant to Rule 424 on May 14, 2013.

A reference to a Note herein refers to the accompanying Notes to Condensed Combined Financial Statements contained in Item 1. Financial Statements. In addition, please read Cautionary Statement Regarding Forward-Looking Statements and Risk Factors for information regarding certain risks inherent in our business.

Cautionary Statement Regarding Forward-Looking Statements

This Quarterly Report and the documents incorporated by reference herein contain forward-looking statements concerning our operations, economic performance and financial condition. Forward-looking statements give our current expectations, contain projections of results of operations or of financial condition, or forecasts of future events. Words such as could, will, may, assume, forecast, position, predict, expect, intend, plan, estimate, anticipate, believe, project, budget, potential, or continue, and similar expressions are used to i forward-looking statements. Without limiting the generality of the foregoing, forward-looking statements contained in this Quarterly Report include our expectations of plans, strategies, objectives, growth and anticipated financial and operational performance, including guidance regarding our and Tallgrass Development s infrastructure programs, revenue projections, capital expenditures and tax position. Forward-looking statements can be affected by assumptions used or by known or unknown risks or uncertainties. Consequently, no forward-looking statements can be guaranteed.

A forward-looking statement may include a statement of the assumptions or bases underlying the forward-looking statement. We believe that we have chosen these assumptions or bases in good faith and that they are reasonable. However, when considering these forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this Quarterly Report. Actual results may vary materially. You are cautioned not to place undue reliance on any forward-looking statements. You should also understand that it is not possible to predict or identify all such factors and should not consider the following list to be a complete statement of all potential risks and uncertainties. Factors that could cause our actual results to differ materially from the results contemplated by such forward-looking statements include:

- changes in general economic conditions;
- competitive conditions in our industry;
- actions taken by third-party operators, processors and transporters;
- the demand for natural gas storage and transportation services;

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- our ability to successfully implement our business plan;
- our ability to complete internal growth projects on time and on budget;
- the price and availability of debt and equity financing;
- the availability and price of natural gas to the consumer compared to the price of alternative and competing fuels;
- competition from the same and alternative energy sources;
- energy efficiency and technology trends;
- operating hazards and other risks incidental to transporting, storing and processing natural gas;
- natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- interest rates;
- labor relations;
- large customer defaults;
- changes in the availability and cost of capital;
- changes in tax status;
- the effects of existing and future laws and governmental regulations;
- the effects of future litigation; and
- certain factors discussed elsewhere in this Quarterly Report.

Forward-looking statements speak only as of the date on which they are made. While we may update these statements from time to time, we are not required to do so other than pursuant to the securities laws.

Overview

We are a growth-oriented Delaware limited partnership that owns, operates, acquires and develops midstream energy assets in North America. We currently provide natural gas transportation and storage services for customers in the Rocky Mountain and Midwest regions through our TIGT System and provide processing services for customers through our Midstream Facilities located in Wyoming.

We intend to leverage our relationship with Tallgrass Development, which owns approximately 64% of our limited partner interests following the initial public offering on May 17, 2013, and utilize the significant experience of our management team to execute our growth strategy of acquiring midstream assets from Tallgrass Development and third parties, increasing utilization of our existing assets and expanding our systems through construction of additional assets.

Our reportable business segments are:

- Gas Transportation and Storage the ownership and operation of interstate natural gas pipelines and integrated natural gas storage facilities that provide services primarily to on-system customers such as third-party LDCs, industrial users and other shippers; and

- Processing the ownership and operation of natural gas processing, treating and fractionation facilities that produce NGLs and residue gas that is sold in local wholesale markets or delivered into pipelines for transportation to additional end markets.

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Recent Developments

Initial Public Offering

On May 17, 2013, TEP closed its initial public offering of 14,600,000 common units at a price of $21.50 per unit, which included 1,550,000 of a possible 1,957,500 common units from the partial exercise of the over-allotment option by the underwriters. Proceeds to TEP from the sale of the common units were approximately $295.9 million, net of certain offering costs and underwriters commissions. The Offering represented the sale to the public of an approximately 36% limited partner interest in TEP.

In connection with the Offering, TD contributed 100% of the membership interests in TIGT and TMID to TEP in exchange for (i) 9,700,000 common units and 16,200,000 subordinated units, representing an approximate 64% limited partner interest in TEP in the aggregate, (ii) TEP s assumption of $400 million of indebtedness related to TD s acquisition of TIGT and TMID and (iii) $85.5 million in cash as reimbursement for a portion of the capital expenditures made by TD to purchase the contributed assets. At the closing of the Offering, TEP used the total proceeds of approximately $295.9 million to repay approximately $295.9 million of the debt assumed from TD.

Partnership Agreement

In connection with the Offering, TEP entered into a revised partnership agreement on May 17, 2013. The revised partnership agreement requires TEP to distribute its available cash on a quarterly basis, subject to certain terms and conditions, beginning with the quarter ending June 30, 2013. No distributions were declared for the three months ended March 31, 2013. TEP anticipates declaring a prorated distribution in the second quarter of 2013 for the period from May 17, 2013 to June 30, 2013.

New Revolving Credit Facility

On May 17, 2013, in connection with the Offering, TEP entered into a $500 million senior secured revolving credit facility with Barclays Bank PLC, as administrative agent, and a syndicate of lenders, which will mature on the fifth anniversary of the closing date of the Offering. On the closing date of the Offering, TEP borrowed $231.0 million under the credit facility, the proceeds of which were used to repay the remaining approximately $104.1 million of debt assumed from TD, a distribution to TD of $31.2 million in net proceeds from the exercise of the underwriter s option to purchase additional Units, $85.5 million to TD as reimbursement for a portion of the capital expenditures made by TD to purchase the contributed assets and the remainder to pay origination fees related to the new revolving credit facility and other fees associated with the Offering, and to fund working capital requirements of TEP. The remaining commitments under the credit facility are available for capital expenditures and permitted acquisitions, to provide for working capital requirements and for other general partnership purposes. The credit facility has an accordion feature that will allow TEP to increase the available revolving borrowings under the credit facility by up to an additional $100 million, subject to TEP s receipt of increased or new commitments from lenders and satisfaction of certain other conditions. In addition, the credit facility includes a sublimit up to $40 million for swing line loans and a sublimit up to $50 million for letters of credit.

TEP s obligations under the credit facility are (i) guaranteed by TEP and each of its existing and subsequently acquired or organized direct or indirect wholly-owned domestic subsidiaries, subject to TEP s ability to designate certain of its subsidiaries as Unrestricted Subsidiaries and (ii) secured by a first priority lien on substantially all of the present and after acquired property owned by TEP and each guarantor (other than real property interests related to TEP s pipelines).

The credit facility contains various covenants and restrictive provisions that, among other things, limits or restricts TEP s ability (as well as the ability of TEP s restricted subsidiaries) to incur or guarantee additional debt, incur certain liens on assets, dispose of assets, make certain distributions, including distributions from available cash, if a default or event of default under the credit agreement then exists or would result therefrom, change the nature of TEP s business, engage in certain mergers or make certain investments and acquisitions, enter into non arms-length transactions with affiliates and designate certain subsidiaries as Unrestricted Subsidiaries, and also requires maintenance of a consolidated leverage ratio of not more than 4.75 to 1.00 (which will be increased to 5.25 to 1.00 for certain measurement periods following the consummation of certain acquisitions) and a consolidated interest coverage ratio of not less than 2.50 to 1.00.

Borrowings under the credit facility bear interest, at TEP s option, at either (a) a base rate, which is a rate equal to the greatest of (i) the prime rate, (ii) the U.S. federal funds rate plus 0.5% and (iii) a one-month reserve adjusted Eurodollar rate plus 1.00%, in each case, plus an applicable margin, or (b) a reserve adjusted Eurodollar rate, plus an applicable margin. Swing line loans bear interest at the base rate plus an applicable margin. For borrowings bearing interest based on the base rate, the applicable margin is initially 1.00%, and for loans bearing interest based on the reserve adjusted Eurodollar rate, the applicable margin is initially 2.00%. After the first full fiscal quarter after the closing date of the Offering, the applicable margin will range from 1.00% to 2.00% for base rate borrowings and 2.00% to 3.00% for reserve adjusted Eurodollar rate borrowings, based upon TEP s total leverage ratio. The unused portion of the credit facility is subject to a commitment fee, which is initially 0.375%, and after the first full fiscal quarter after the closing date of the Offering, is either 0.375% or 0.500%, based on TEP s total leverage ratio.

How We Evaluate Our Operations

We evaluate our results using, among other measures, contract mix and volumes, operating costs and expenses, Adjusted EBITDA and distributable cash flow. Adjusted EBITDA and distributable cash flow are non-GAAP measures and are defined below.

Contract Mix and Volumes

Our results are driven primarily by the volume of natural gas transportation and storage capacity under firm contracts, the volume of natural gas that we process and the fees assessed for such services.

Operating Costs and Expenses

The primary components of our operating costs and expenses that we evaluate include cost of sales and transportation services, operations and maintenance and general and administrative. Our operating expenses in the transportation and storage segment are driven primarily by expenses related to the operation, maintenance and growth of our asset base.

Adjusted EBITDA and Distributable Cash Flow

Adjusted EBITDA and distributable cash flow are non-GAAP supplemental financial measures that management and external users of our combined financial statements, such as industry analysts, investors, lenders and rating agencies, may use to assess:

- our operating performance as compared to other publicly traded partnerships in the midstream energy industry, without regard to historical cost basis or, in the case of Adjusted EBITDA, financing methods;
- the ability of our assets to generate sufficient cash flow to make distributions to our unitholders;
- our ability to incur and service debt and fund capital expenditures; and
- the viability of acquisitions and other capital expenditure projects and the returns on investment of various expansion and growth opportunities.

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We believe that the presentation of Adjusted EBITDA and distributable cash flow provides useful information to investors in assessing our financial condition and results of operations. Adjusted EBITDA and distributable cash flow should not be considered alternatives to net income, operating income, cash from operations or any other measure of financial performance or liquidity presented in accordance with GAAP. Adjusted EBITDA and distributable cash flow have important limitations as analytical tools because they exclude some but not all items that affect net income and net cash provided by operating activities. Additionally, because Adjusted EBITDA and distributable cash flow may be defined differently by other companies in our industry, our definition of Adjusted EBITDA and distributable cash flow may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

Non-GAAP Measures

We define Adjusted EBITDA as net income before interest, income taxes, depreciation and amortization, non-cash income or loss related to derivative instruments and non-cash long-term compensation expense. Although we have not quantified distributable cash flow on a historical basis, after the closing of the Offering we intend to use distributable cash flow, which we define as Adjusted EBITDA less net cash paid for interest expense and maintenance capital expenditures, to analyze our performance. Neither Adjusted EBITDA nor distributable cash flow will be impacted by changes in working capital balances that are reflected in operating cash flow. Distributable cash flow and Adjusted EBITDA are not presentations made in accordance with GAAP.

Prior to November 13, 2012, TEP Pre-Predecessor elected to designate derivative instruments in the Gas Transportation and Storage segment as cash flow hedges. As a result, TEP Pre-Predecessor did not record any non-cash income or loss related to derivative instruments. Effective November 13, 2012, TEP Predecessor de-designated these cash flow hedges, resulting in the recognition of non-cash income and losses related to derivative instruments in periods subsequent to November 13, 2012. There are no derivative instruments in the Processing segment for any of the periods presented.

The following table presents a reconciliation of Adjusted EBITDA to (i) net income and net cash provided by operating activities, the most directly comparable GAAP financial measures, for each of the periods indicated:

	TEP Predecessor Three Months Ended March 31, 2013 (in thousands)	TEP Pre-Predecessor Three Months Ended March 31, 2012 (in thousands)
Reconciliation of Adjusted EBITDA to Net Income		
Net income	$ 5,071	$ 17,147
Add:		
Interest (income) expense, net	5,564	
Depreciation and amortization expense	7,546	5,959
Non-cash loss related to derivative instruments	919	
Texas Margin Tax		89
Adjusted EBITDA	**$ 19,100**	**$ 23,195**
Reconciliation of Adjusted EBITDA to Net Cash Provided by Operating Activities		
Net cash provided by operating activities	$ 32,021	$ 32,451
Add:		
Interest (income) expense, net	5,564	
Texas Margin Tax		89
Other, including changes in operating working capital	(18,485)	(9,345)
Adjusted EBITDA	**$ 19,100**	**$ 23,195**

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The following table presents a reconciliation of Adjusted EBITDA by segment to segment operating income, the most directly comparable GAAP financial measure, for each of the periods indicated:

	TEP Predecessor Three Months Ended March 31, 2013 (in thousands)	TEP Pre-Predecessor Three Months Ended March 31, 2012 (in thousands)
Reconciliation of Adjusted EBITDA to Operating Income in the Gas Transportation and Storage Segment		
Operating income	$ 5,081	$ 11,082
Add:		
Depreciation and amortization expense	5,927	5,179
Non-cash income related to derivative instruments	919	
Other income (expense)	339	(421)
Segment Adjusted EBITDA	**$ 12,266**	**$ 15,840**
Reconciliation of Adjusted EBITDA to Operating Income in the Processing Segment		
Operating income	$ 5,215	$ 6,575
Add:		
Depreciation and amortization expense	1,619	780
Segment Adjusted EBITDA	**$ 6,834**	**$ 7,355**

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Results of Operations

The following provides a summary of our results of operations for our Predecessor for the periods indicated:

	TEP Predecessor Three Months Ended March 31, 2013 (in thousands, except operating data)	TEP Pre-Predecessor Three Months Ended March 31, 2012 (in thousands, except operating data)
Statement of Operation Data		
Revenues:		
Natural gas liquids sales	$ 33,401	$ 36,011
Natural gas sales	301	870
Transportation services	24,337	28,156
Other operating revenues	2,219	1,492
Total revenues	60,258	66,529
Operating costs and expenses:		
Cost of sales and transportation services	28,884	29,435
Operations and maintenance	7,121	8,020
Depreciation and amortization	7,546	5,959
General and administrative	4,634	3,405
Taxes, other than income taxes	1,777	2,053
Total operating costs and expenses	49,962	48,872
Operating income	10,296	17,657
Interest income (expense), net	(5,564)	
Other income (expense), net	339	(421)
Income before income taxes	5,071	17,236
Texas Margin Taxes		89
Net Income to Member	$ 5,071	$ 17,147
Other Financial Data[(1)]		
Adjusted EBITDA	$ 19,100	$ 23,195
Operating Data		
Operating Data (Mmcf/d):		
Transportation firm contracted capacity	667	797
Natural gas processing inlet volumes	127	123

(1) For more information regarding Adjusted EBITDA and a reconciliation of Adjusted EBITDA to its most directly comparable GAAP measure, please see Management s Discussion and Analysis Non-GAAP Financial Measures above.

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	TEP Predecessor Three Months Ended March 31, 2013 (in thousands)		TEP Pre-Predecessor Three Months Ended March 31, 2012 (in thousands)	
Segment Financial Data Gas Transportation and Storage				
Revenues:				
Natural gas sales	$	(919)	$	
Transportation services		24,508		28,362
Other operating revenues		8		236
Total revenues		23,597		28,598
Operating costs and expenses:				
Cost of sales and transportation services		1,611		1,255
Operations and maintenance		5,569		6,441
Depreciation and amortization		5,927		5,179
General and administrative		3,743		2,682
Taxes, other than income taxes		1,666		1,959
Total operating costs and expenses		18,516		17,516
Operating income	$	5,081	$	11,082
Segment Adjusted EBITDA	$	12,266	$	15,840
Segment Financial Data Processing				
Revenues:				
Natural gas liquids sales	$	33,401	$	36,011
Natural gas sales		1,220		870
Other operating revenues		2,211		1,256
Total revenues		36,832		38,137
Operating costs and expenses:				
Cost of sales and transportation services		27,444		28,386
Operations and maintenance		1,552		1,579
Depreciation and amortization		1,619		780
General and administrative		891		723
Taxes, other than income taxes		111		94
Total operating costs and expenses		31,617		31,562
Operating income	$	5,215	$	6,575
Segment Adjusted EBITDA	$	6,834	$	7,355

Three Months Ended March 31, 2013 Compared to the Three Months Ended March 31, 2012

Revenues. Total revenues were $60.3 million for the three months ended March 31, 2013, compared to $66.5 million for the three months ended March 31, 2012, which represents a 9% decrease in total revenues. The decrease in revenues in the Gas Transportation and Storage segment and the Processing segment was 17% and 3%, respectively.

In the Gas Transportation and Storage segment a decrease of $3.9 million, or 14%, in transportation services revenue was attributable to a reduction in firm reservation fees, corresponding to the decrease in transportation firm contracted capacity shown above, and lower throughput volume. Natural gas sales are typically not made during the first quarter of the fiscal year because any natural gas received from our customers as compensation for fuel used by our system is injected into storage in order to meet operational requirements during the winter withdrawal season. The $0.9 million loss in natural gas sales during the three months ended March 31, 2013 represents a noncash mark-to-market loss on derivatives that are intended to hedge future sales of natural gas that is currently held in our storage facility. The Pre-Predecessor utilized hedge accounting and therefore there is no associated noncash mark-to-market gain or loss during the three months ended March 31, 2012.

In the Processing segment, natural gas liquids sales represent 91% of total segment revenue during the three months ended March 31, 2013. The $2.6 million, or 7%, decline in natural gas liquids sales for the three months ended March 31, 2013 compared to the three months ended March 31, 2012 is primarily attributable to an 11% reduction in average NGL prices during the three months ended March 31, 2013.

Operating costs and expenses. Operating costs and expenses were $50.0 million for the three months ended March 31, 2013 compared to $48.9 million for the three months ended March 31, 2012, which represents a 2% increase.

Cost of sales and transportation services decreased by $0.6 million, or 2%, in the three months ended March 31, 2013 when compared to same period in the prior year. In the Transportation and Storage segment, there was an overall increase in costs of sales and transportation services of $0.4 million, or 28%, caused primarily by a $4.1 million reduction in fuel recoveries related to a reduction in recovery rates offset by a $3.5 million reduction in costs associated with operational balancing agreements related to a decrease in the price of natural gas. In the Processing segment, costs of sales and transportation services decreased by $0.9 million, or 3%, in the three months ended March 31, 2013 when compared to the prior year period as a result of decreased average NGL prices.

Operations and maintenance costs decreased $0.9 million, or 11%, in the three months ended March 31, 2013 when compared to the same period in the prior year. Nearly all of this decrease occurred in the Transportation and Storage segment and was primarily related to a reduction in facility electric costs, vehicle expenses and field employee costs.

Depreciation and amortization was higher in both segments in the three months ended March 31, 2013 compared to the three months ended March 31, 2012 due to the higher cost basis of property, plant and equipment as a result of the acquisition of TIGT and TMID on November 13, 2012.

General and administrative expenses in the three months ended March 31, 2013 were $1.2 million, or 36% higher than they were in the comparable prior period. This increase is largely reflective of Kinder Morgan s scale advantage in supporting similar required administrative functions by a substantially larger number of operated business.

Texas Margin Taxes. TEP Pre-Predecessor incurred Texas Margin Taxes because it was a part of an affiliated group that generated sales in the State of Texas. Subsequent to our acquisition by TD in November 2012, we are no longer subject to Texas Margin Taxes or any other income-based taxes based on currently enacted tax legislation.

Liquidity and Capital Resources Overview

Our primary source of liquidity for the three months ended March 31, 2013 was cash generated from operations. We expect our sources of liquidity in the future to include:

- cash generated from our operations;
- proceeds from the sale of the Pony Express Assets;
- borrowing capacity available under our revolving credit facility that was entered into on May 17, 2013 in connection with the Offering; and
- future issuances of additional partnership units and debt securities.

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We believe that cash on hand, cash generated from operations and availability under our credit facility will be adequate to meet our operating needs, our planned short-term capital and debt service requirements and our planned cash distributions to unitholders. We believe that future internal growth projects or potential acquisitions will be funded primarily through borrowings under our credit facility or through issuances of debt and equity securities.

Working Capital

Working capital is the amount by which current assets exceed current liabilities. As of March 31, 2013, we had a working capital deficit of $56.4 million compared to a working capital deficit of $43.8 million at December 31, 2012.

Our working capital requirements have been and we expect will continue to be primarily driven by changes in accounts receivable and accounts payable. Factors impacting changes in accounts receivable and accounts payable could include the timing of collections from customers and payments to suppliers, as well as the level of spending for capital expenditures and changes in the market prices of energy commodities that we buy and sell in the normal course of business. The overall increase in the working capital deficit from December 31, 2012 to March 31, 2013 was primarily attributable to an increase in accounts payable resulting from timing differences and $6.0 million of interest accrued during the first quarter of 2013 related to the debt allocated from TD.

A material adverse change in operations or available financing under our revolving credit facility could impact our ability to fund our requirements for liquidity and capital resources in the future.

Cash Flows

The following table and discussion presents a summary of our cash flow for the periods indicated:

	TEP Predecessor Three Months Ended March 31, 2013 (in thousands)	TEP Pre-Predecessor Three Months Ended March 31, 2012 (in thousands)
Net cash provided by (used in):		
Operating activities	$ 32,021	$ 32,451
Investing activities	$ (8,937)	$ (5,696)
Financing activities	$ (23,084)	$ (26,755)

Operating Activities. Cash flows provided by operating activities were $32.0 million and $32.5 million for the three months ended March 31, 2013 and 2012, respectively.

Operating cash flow remained consistent overall, with a decrease in net income of $12.1 million, offset by a $2.4 million increase in depreciation and amortization due to the increased cost basis of property, plant and equipment as discussed above, and an $10.8 million increase in net cash provided by changes in working capital primarily due to an increase in accounts payable resulting from timing differences, accrued taxes, and accrued interest related to the debt allocated from TD offset by a decrease in cash inflows from related party balances.

Investing Activities. Cash flows used in investing activities were $8.9 million and $5.7 million for the three months ended March 31, 2013 and 2012, respectively. Investing cash flows are primarily attributable to capital expenditures.

During the three months ended March 31, 2013, net cash used in investing activities was driven by $8.9 million in capital expenditures primarily related to the capacity expansion and efficiency upgrade projects at TMID and the replacement gas facilities associated with the Pony Express project at TIGT. In the three months

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ended March 31, 2012, net cash used in investing activities was driven by $5.2 million of net expenditures associated with the net purchases of working gas in underground storage. Effective November 13, 2012, TEP Predecessor adopted an accounting policy in which working gas is accounted for as part of inventory. As a result, cash flows associated with changes in gas in underground storage are now presented as cash flows from operating activities.

Financing Activities. Prior to November 13, 2012, cash flows used in financing activities consisted entirely of cash distributions paid to Kinder Morgan, as TEP Pre-Predecessor participated in Kinder Morgan s centralized cash management system prior to that time. Between November 13, 2012 and May 17, 2013, TEP Predecessor participated in a similar centralized cash management system with TD, and upon the completion of the Offering on May 17, 2013, TIGT and TMID entered into one with TEP. Under these cash management systems, all cash balances of the Predecessor Entities are swept on a daily basis and the balances are periodically settled and recorded as equity distributions. Therefore, the Predecessor Entities do not have cash balances at the end of any period and cash flows from financing activities is equal to the total of cash flows from operating activities and cash flows from investing activities in all periods presented.

Distributions

Following consummation of our initial public offering, we intend to pay quarterly distributions at an initial rate of $0.2875 per unit. As of the date of this Quarterly Report, we have a total of 41,326,531 common, subordinated and general partner units outstanding, which would equate to an aggregate distribution of approximately $11.9 million per quarter and $47.5 million per year. We do not have a legal obligation to pay distributions except as provided in our partnership agreement. No distribution was made for the three months ended March 31, 2013. We expect that the amount of any distribution declared and paid for the second quarter of 2013 will be on a prorated basis for the period from the closing of our initial public offering on May 17, 2013 through June 30, 2013.

Capital Requirements

Our business is capital-intensive, requiring significant investment to maintain and improve existing assets. We have budgeted approximately $44 million for capital expenditures for the remainder of 2013. We currently expect maintenance capital expenditures to be in the range of $8 million to $9 million for the remainder of 2013. Our budgeted expansion capital expenditures for the remainder of 2013 primarily relate to the ongoing capacity expansion and efficiency upgrade projects at TMID. In addition, we estimate that we will incur expansion capital expenditures related to the Pony Express project of approximately $53.6 million, for which we will receive reimbursement from TD.

Contractual Obligations

There have been no material changes in our contractual obligations as reported in the Prospectus.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Critical Accounting Policies and Estimates

The condensed combined financial statements of the Predecessor Entities are prepared in conformity with GAAP, which requires the use of estimates, judgments and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the periods presented. Our significant accounting policies are described in Note 2 to the audited combined financial statements included in the Prospectus. Our critical accounting estimates are described in Management s

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Discussion and Analysis of Financial Condition and Results of Operations in the Prospectus. The preparation of these financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosure of contingent assets and liabilities. The critical accounting policies are considered by management to be critical to an understanding of our financial statements as their application places the most significant demands on management s judgment. Due to the inherent uncertainties involved with this type of judgment, actual results could differ significantly from estimates and may have a material adverse impact on our results of operations, equity or cash flows. We have reviewed and determined that those policies remain the Predecessor Entities critical accounting policies as of and for the three months ended March 31, 2013.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

The profitability of our processing contracts that include keep whole or percent of proceeds components is affected by volatility in prevailing NGL and natural gas prices. We do not currently hedge the commodity exposure in our processing contracts. Our Processing segment comprised approximately 37% of our Adjusted EBITDA for the three months ended March 31, 2013.

We also have a limited amount of direct commodity price exposure related to electrical compression costs and lost and unaccounted for gas on the TIGT System. Historically, we have entered into derivative contracts with third parties for the purpose of hedging these commodity price exposures. As of March 31, 2013, we had natural gas swaps outstanding with a notional volume of approximately 1.7 Bcf, representing a portion of the natural gas that is expected to be sold by our Gas Transportation and Storage segment through the end of 2013. The fair value of these swaps was a liability of approximately $0.7 million at March 31, 2013.

We measure the risk of price changes in our natural gas swaps utilizing a sensitivity analysis model. The sensitivity analysis measures the potential income or loss (i.e., the change in fair value of the derivative instruments) based upon a hypothetical movement in the underlying quoted market prices. In addition to these variables, the fair value of each portfolio is influenced by fluctuations in the notional amounts of the instruments and the discount rates used to determine the present values. We enter into derivative contracts solely for the purpose of mitigating the risks that accompany certain of our business activities and, therefore, both the sensitivity analysis model and the change in the market value of our outstanding derivative contracts are offset largely by changes in the value of the underlying physical natural gas sales.

Our sensitivity analysis represents an estimate of the reasonably possible gains and losses that would be recognized on the natural gas derivative contracts (including fixed price swaps and basis swaps) assuming hypothetical movements in future market prices and is not necessarily indicative of actual results that may occur. It does not represent the maximum possible loss or any expected loss that may occur, since actual future gains and losses will differ from those estimated. Actual gains and losses may differ from estimates due to actual fluctuations in market prices, operating exposures and the timing thereof, as well as changes in the notional volumes of our outstanding derivatives during the year.

Interest Rate Risk

As described in Recent Developments above, at the closing of the Offering, we entered into a $500 million revolving credit facility. Borrowings under the credit facility will bear interest, at our option, at either (a) a base rate, which will be a rate equal to the greatest of (i) the prime rate, (ii) the U.S. federal funds rate plus 0.5% and (iii) a one-month reserve adjusted Eurodollar rate plus 1.00% or (b) a reserve adjusted Eurodollar Rate, plus, in each case, an applicable margin. For loans bearing interest based on the base rate, the applicable margin will initially be 1.00%, and for loans bearing interest based on the reserve adjusted Eurodollar rate, the applicable margin will initially be 2.00%. After the first full fiscal quarter after the closing date of the Offering, the

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applicable margin will range from 1.00% to 3.00%, based upon our total leverage ratio and whether we have elected the base rate or the reserve adjusted Eurodollar rate. We may or may not hedge the interest on portions of our borrowings under the credit facility from time-to-time through interest rate swaps or caps in order to manage risks associated with floating interest rates. Additionally, we may choose longer Eurodollar borrowing terms in order to fix all or a portion of our borrowings for a period of time.

Credit Risk

We are exposed to credit risk. Credit risk represents the loss that we would incur if a counterparty fails to perform under its contractual obligations. We manage our exposure to credit risk associated with customers to whom we extend credit through a credit approval process which includes credit analysis, the establishment of credit limits and ongoing monitoring procedures. We may request letters of credit, cash collateral, prepayments or guarantees as forms of credit support. We have historically experienced only minimal credit losses in connection with our receivables.

A substantial majority of our revenue is produced under long-term, fee-based contracts with high-quality customers. The customer base we currently serve under these contracts generally has a strong credit profile, with the majority having investment grade credit ratings as of March 31, 2013.

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our principal executive officer and principal financial officer, has evaluated the effectiveness our disclosure controls and procedures (as defined in Rule 13a- 15(e) or Rule 15d- 15(e) under the Securities Exchange Act of 1934) as of the end of the period covered by this report, and has concluded that our disclosure controls and procedures are effective to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported, within the time periods specified in the Securities and Exchange Commission s rules and forms including, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosures.

Changes in Internal Control over Financial Reporting

During the first quarter of 2013, TEP completed several stages of the transition of our financial systems to a new integrated accounting system, which was utilized to produce financial information contained in this Quarterly Report. There have not been any other changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the quarter ended March 31, 2013 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management s Assessment of Internal Control over Financial Reporting

The SEC, as required by Section 404 of the Sarbanes-Oxley Act, adopted rules requiring every public company that files reports with the SEC to include a management report on such company s internal control over financial reporting in its annual report. Pursuant to the recently enacted Jumpstart Our Business Startups Act of 2012 (the JOBS Act), our independent registered public accounting firm will not be required to attest to the effectiveness of our internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002 for up to five years or through such earlier date that we are no longer an emerging growth company as defined in the JOBS Act. Our first Annual Report on Form 10-K will not include a report of management s assessment regarding internal control over financial reporting or an attestation report of our independent registered public accounting firm due to a transition period established by SEC rules applicable to newly public companies. Our management will be required to provide an assessment of the effectiveness of our internal control over financial reporting as of December 31, 2014.

PART II OTHER INFORMATION

Item 1. Legal Proceedings

See Note 12 Legal and Environmental Matters to the combined financial statements included in Part 1 Item 1. Financial Statements of this Quarterly Report, which is incorporated here by reference.

Item 1A. Risk Factors

Limited partner interests are inherently different from shares of capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in similar businesses. If any of the following risks were to occur, our business, financial condition or results of operations could be materially adversely affected. In that case, we might not be able to pay the minimum quarterly distribution on our common units or the trading price of our common units could decline.

Risks Related to Our Business

We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner and its affiliates, to enable us to pay the minimum quarterly distribution to holders of our common and subordinated units.

In order to pay the minimum quarterly distribution of $0.2875 per unit, or $1.15 per unit on an annualized basis, we will require available cash of approximately $11.9 million per quarter, or $47.5 million per year, based on the number of common, subordinated and general partner units currently outstanding. We may not have sufficient available cash from operating surplus each quarter to enable us to pay the minimum quarterly distribution. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the level of firm transportation and storage capacity sold and the volume of natural gas we transport, store and process;
- the level of production of oil and natural gas and the resultant market prices of natural gas and NGLs;
- regional, domestic and foreign supply and perceptions of supply of natural gas; the level of demand and perceptions of demand in our end-user markets; and actual and anticipated future prices of natural gas and other commodities (and the volatility thereof), which may impact our ability to renew and replace firm transportation, storage and processing agreements;
- regulatory action affecting the supply of, or demand for, natural gas, the rates we can charge on our assets, how we contract for services, our existing contracts, our operating costs or our operating flexibility;
- changes in the fees we charge for our services;
- the effect of seasonal variations in temperature on the amount of natural gas that we transport, store, process and treat;
- the relationship between natural gas and NGL prices and resulting effect on processing margins;
- the realized pricing impacts on revenues and expenses that are directly related to commodity prices;

the level of competition from other midstream energy companies in our geographic markets;

the creditworthiness of our customers;

the level of our operating and maintenance costs;

damages to pipelines, facilities, related equipment and surrounding properties caused by earthquakes, floods, fires, severe weather, explosions and other natural disasters and acts of terrorism;

- outages at our processing facilities;
- leaks or accidental releases of hazardous materials into the environment, whether as a result of human error or otherwise; and
- prevailing economic conditions.

In addition, the actual amount of cash we will have available for distribution will depend on the other factors, including:

- the level and timing of capital expenditures we make;
- the level of our general and administrative expenses, including reimbursements to our general partner and its affiliates, including Tallgrass Development, for services provided to us;
- the cost of acquisitions, if any;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions contained in our debt agreements;
- the amount of cash reserves established by our general partner; and
- other business risks affecting our cash levels.

If we are not able to renew or replace expiring customer contracts at favorable rates or on a long-term basis, our financial condition, results of operation, cash flows and ability to make cash distributions to our unitholders will be adversely affected. We have experienced decreases in revenues as compared to historical periods resulting from decreased renewals of long-haul firm capacity contracts with off-system customers over the last few years. If this trend continues, our ability to make cash distributions to our unitholders may be materially impacted.

We transport, store and process a substantial majority of the natural gas on our systems under long-term contracts with terms of various durations. For the year ended December 31, 2012, approximately 81% of our transportation and storage revenues were generated under firm transportation and storage contracts. Our firm transportation and storage contracts have a weighted average maturity of approximately four years and two years, respectively as of December 31, 2012. As of December 31, 2012, the weighted-average duration of our processing contracts was over four years. As these contracts expire, we may be unable to obtain new contracts on terms similar to those of our existing contracts, or at all. If we are unable to promptly resell capacity from expiring contracts on equivalent terms, our revenues may decrease and our ability to make cash distributions to our unitholders may be materially impaired.

For example, over the past several years, a number of our transportation and storage customers have opted not to renew their contracts for service on the TIGT System. We believe those non-renewals have been caused both by increased competition from large diameter long-haul pipeline systems that are more efficient and cost effective at transporting natural gas over long distances as well as reduced drilling activity for dry gas in the Rocky Mountain region. These former customers are generally large producers that primarily used the TIGT System to access interstate pipelines for ultimate delivery to consuming markets outside our areas of operations, as opposed to our current customer base, which is primarily comprised of on-system regional customers, such as LDCs. The non-renewal of these transportation contracts has resulted in decreases in firm contracted capacity on the TIGT System and related decreases in total revenue. For example, our average firm contracted capacity decreased from 842 MMcf/d for the year ended December 31, 2010 to 754 MMcf/d for the year ended December 31, 2012 and transportation services revenue decreased from $142.4 million to $106.3 million over the same period, primarily due to the loss of revenue from the non-renewal of transportation contracts.

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We also may be unable to maintain the long-term nature and economic structure of our current contract portfolio over time. Depending on prevailing market conditions at the time of a contract renewal, transportation, storage and processing customers with fee-based contracts may desire to enter into contracts under different fee arrangements, and our potential customers may be generally unwilling to enter into long-term contracts. To the extent we are unable to renew or replace our existing contracts on terms that are favorable to us or successfully manage the long-term nature and economic structure of our contract mix over time, our revenues and cash flows could decline and our ability to make distributions to our unitholders could be materially and adversely affected. In addition, if an existing customer terminates or breaches its long-term firm transportation, storage or processing contract, we may be subject to a loss of revenue if we are unable to promptly resell the capacity to another customer on substantially equivalent terms.

Our ability to renew or replace our expiring contracts on terms similar to, or more attractive than, those of our existing contracts is uncertain and depends on a number of factors beyond our control, including:

- the level of existing and new competition to provide transportation, storage and processing services to our markets;
- the macroeconomic factors affecting natural gas gathering economics for our current and potential customers;
- the balance of supply and demand for natural gas, on a short-term, seasonal and long-term basis, in the markets we serve;
- the extent to which the customers in our markets are willing to contract on a long-term basis; and
- the effects of federal, state or local regulations on the contracting practices of our customers.

Furthermore, we do not have firm contracts in place for the additional capacity associated with the expansion of our Casper and Douglas processing plants, which is scheduled to be completed in the second half of 2013. If we are not able to enter into processing contracts at favorable rates or on a long term basis with respect to this expanded capacity or otherwise utilize the capacity, our financial condition, results of operation, cash flows and ability to make cash distributions to our unitholders will be adversely affected.

Increased competition from other companies that provide natural gas transportation, storage and processing services, or from alternative fuel sources, could have a negative impact on the demand for our services, which could materially and adversely affect our financial results.

Our ability to renew or replace our existing contracts at rates sufficient to maintain current revenues and current cash flows could be adversely affected by the activities of our competitors. Some of our competitors have greater financial, managerial and other resources than we do and control substantially more transportation, storage and processing capacity than we do. In addition, some of our competitors have assets in closer proximity to natural gas supplies and have available idle capacity in existing assets that would not require new capital investments for use. For example, several pipelines access many of the same basins as the TIGT System and transport gas to customers in the Rocky Mountain and Midwest regions of the United States. Our competitors may expand or construct new transportation, storage or processing systems that would create additional competition for the services we provide to our customers, or our customers may develop their own transportation, storage and processing facilities in lieu of using ours. The potential for the construction of new processing facilities in our areas of operation is particularly acute due to the unregulated nature of the processing industry. Furthermore, Tallgrass Development and its affiliates are not limited in their ability to compete with us.

If our competitors were to substantially decrease the prices at which they offer their services, we may be unable to compete effectively and our cash flows and ability to make distributions to our unitholders may be materially impaired.

Further, natural gas as a fuel competes with other forms of energy available to users, including electricity, coal and liquid fuels. Increased demand for such forms of energy at the expense of natural gas could lead to a reduction in demand for our services.

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All of these competitive pressures could make it more difficult for us to renew our existing long-term, firm transportation, storage and processing contracts when they expire or to attract new customers as we seek to expand our business, which could have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, competition could intensify the negative impact of factors that decrease demand for natural gas in the markets we serve, such as adverse economic conditions, weather, higher fuel costs and taxes or other governmental or regulatory actions that directly or indirectly increase the cost or limit the use of natural gas.

If we are unable to make acquisitions on economically acceptable terms from Tallgrass Development or third parties, our future growth will be limited, and the acquisitions we do make may reduce, rather than increase, our cash generated from operations on a per unit basis.

Our ability to grow depends, in part, on our ability to make acquisitions that increase our cash generated from operations on a per unit basis. The acquisition component of our strategy is based, in large part, on our expectation of ongoing divestitures of midstream energy assets by industry participants, including Tallgrass Development. Other than Tallgrass Development s obligation to offer us certain assets pursuant to the right of first offer under the Omnibus Agreement (the Omnibus Agreement) entered into in connection with our Offering between us, our general partner, Tallgrass Development and its general partner, we have no contractual arrangement with Tallgrass Development that would require it to provide us with an opportunity to acquire midstream assets that it may sell. Accordingly, while we believe Tallgrass Development will be incentivized pursuant to its economic relationship with us to offer us opportunities to purchase midstream assets, there can be no assurance that any such offer will be made, and there can be no assurance we will reach agreement on the terms with respect to any acquisition opportunities offered to us by Tallgrass Development. Furthermore, many factors could impair our access to future midstream assets, including a change in control of Tallgrass Development or a transfer of the incentive distribution rights as defined in our partnership agreement (IDRs) by our general partner to a third party. A material decrease in divestitures of midstream energy assets from Tallgrass Development or otherwise would limit our opportunities for future acquisitions and could have a material adverse effect on our business, results of operations, financial condition and ability to make quarterly cash distributions to our unitholders.

Our future growth and ability to increase distributions will be limited if we are unable to make accretive acquisitions from Tallgrass Development or third parties because, among other reasons, (i) Tallgrass Development elects not to sell or contribute additional assets to us or to offer acquisition opportunities to us, (ii) we are unable to identify attractive third-party acquisition opportunities, (iii) we are unable to negotiate acceptable purchase contracts with Tallgrass Development or third parties, (iv) we are unable to obtain financing for these acquisitions on economically acceptable terms, (v) we are outbid by competitors or (vi) we are unable to obtain necessary governmental or third-party consents. Furthermore, even if we do make acquisitions that we believe will be accretive, these acquisitions may nevertheless result in a decrease in the cash generated from operations on a per unit basis.

Any acquisition involves potential risks, including, among other things:

- mistaken assumptions about volumes, revenue and costs, including synergies and potential growth;
- an inability to maintain or secure adequate customer commitments to use the acquired systems or facilities;
- an inability to integrate successfully the assets or businesses we acquire;
- the assumption of unknown liabilities for which we are not indemnified or for which our indemnity is inadequate;
- the diversion of management s and employees attention from other business concerns;
- unforeseen difficulties operating in new geographic areas or business lines; and

a decrease in liquidity and increased leverage as a result of using significant amounts of available cash or debt to finance an acquisition.

If any acquisition eventually proves not to be accretive to our distributable cash flow per unit, it could have a material adverse effect on our business, results of operations, financial condition and ability to make quarterly cash distributions to our unitholders.

If we are unable to obtain needed capital or financing on satisfactory terms to fund expansions of our asset base, our ability to make quarterly cash distributions may be diminished or our financial leverage could increase.

In order to expand our asset base through acquisitions or capital projects, we may need to make expansion capital expenditures. If we do not make sufficient or effective expansion capital expenditures, we will be unable to expand our business operations and may be unable to maintain or raise the level of our quarterly cash distributions. We will be required to use cash from our operations or incur borrowings or sell additional common units or other limited partner interests in order to fund our expansion capital expenditures. Using cash from operations will reduce cash available for distribution to our common unitholders. Our ability to obtain bank financing or to access the capital markets for future equity or debt offerings may be limited by our financial condition at the time of any such financing or offering as well as the covenants in our debt agreements, general economic conditions and contingencies and uncertainties that are beyond our control. Even if we are successful in obtaining funds for expansion capital expenditures through equity or debt financings, the terms thereof could limit our ability to pay distributions to our common unitholders. In addition, incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional limited partner interests may result in significant common unitholder dilution and increase the aggregate amount of cash required to maintain the then-current distribution rate, which could materially decrease our ability to pay distributions at the then-current distribution rate.

We do not currently have any commitment with our general partner or other affiliates, including Tallgrass Development, to provide any direct or indirect financial assistance to us.

We are exposed to direct commodity price risk with respect to the majority of our processing revenues, and our exposure to direct commodity price risk may increase in the future.

Our processing segment operates under two types of contractual arrangements that expose our cash flows to increases and decreases in the price of natural gas and NGLs: percentage-of-proceeds and keep-whole arrangements. As of December 31, 2012, approximately two-thirds of the reserved capacity in our processing segment was contracted under percent of proceeds or keep whole arrangements. Under percentage-of-proceeds arrangements, we generally purchase natural gas from producers and retain from the sale an agreed percentage of pipeline-quality gas and NGLs resulting from our processing activities at market prices. These arrangements provide upside in high commodity price environments, but result in lower margins in low commodity price environments. Under keep-whole arrangements, we are required to replace a contractually specified percentage of the Btu content of the inlet wet gas that we process with a combination of NGLs that we produce and dry natural gas, some of which we must purchase at market prices. Under these types of arrangements our revenues and our cash flows increase or decrease as the prices of natural gas and NGLs fluctuate. The relationship between natural gas prices and NGL prices may also affect our profitability. When natural gas prices are low relative to NGLs prices, it is more profitable for us to process natural gas under keep-whole arrangements. When natural gas prices are high relative to NGLs prices, it is less profitable for us and our customers to process natural gas both because of the higher value of natural gas and of the increased cost (principally that of natural gas as a feedstock and a fuel) of separating the mixed NGLs from the natural gas. As a result, we may experience periods in which higher natural gas prices relative to NGL prices reduce our processing margins or reduce the volume of natural gas processed at some of our plants. In addition, NGL prices have historically been correlated to the market price of oil and as a result any significant changes in oil prices could also indirectly impact our operations. NGL and natural gas prices are volatile and are impacted by changes in the supply and demand for NGLs and natural gas, as well as market uncertainty. We do not currently hedge the commodity exposure in our processing contracts and, as a result, our revenues, financial condition and results of operations could be adversely impacted by

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fluctuations in the prices of natural gas and NGLs. As a result of our commodity price exposure, significant prolonged changes in natural gas and NGL prices could have a material adverse effect on our financial condition, results of operations and our ability to make cash distributions to our unitholders.

If third-party pipelines or other midstream facilities interconnected to our systems become partially or fully unavailable, or if the volumes we transport do not meet the natural gas quality requirements of such pipelines or facilities, our revenues and our ability to make distributions to our unitholders could be adversely affected.

Our natural gas transportation, storage and processing facilities connect to other pipelines or facilities owned and operated by unaffiliated third parties, such as Phillips 66 Company and others. For example, a substantial majority of the NGLs we process are transported on the Powder River pipeline owned by Phillips 66 Company, and therefore, any downtime on this pipeline as a result of maintenance or force majeure would adversely affect us. The continuing operation of such third-party pipelines, processing plants and other midstream facilities is not within our control. These pipelines, plants and other midstream facilities may become unavailable because of testing, turnarounds, line repair, reduced operating pressure, lack of operating capacity, regulatory requirements, curtailments of receipt or deliveries due to insufficient capacity or because of damage from weather events or other operational hazards. In addition, if the costs to us to access and transport on these third-party pipelines significantly increase, our profitability could be reduced. If any such increase in costs occurred, if any of these pipelines or other midstream facilities become unable to receive, transport or process natural gas, or if the volumes we transport or process do not meet the natural gas quality requirements of such pipelines or facilities, our revenues and our ability to make quarterly cash distributions to our unitholders could be adversely affected.

Our ability to abandon and sell the Pony Express Assets to Tallgrass Development in connection with the Pony Express Project is subject to the timing and receipt of governmental approvals.

The abandonment and sale of the Pony Express Assets to Tallgrass Development in connection with the Pony Express Project requires approval from the FERC, which is uncertain and beyond our control. Although our business strategy includes the abandonment and sale of the Pony Express Assets, we may not be able to obtain all required governmental approvals for such abandonment within our currently anticipated schedule or at all, which could result in sustained under-utilization of the Pony Express Assets and a failure to capture anticipated improvements in the cost of operations on the TIGT System. We have also forecasted a reduction in interest expense during the twelve- month period ending June 30, 2014 of $2.3 million as a result of using the anticipated proceeds from our initial sale of the Pony Express Assets to reduce outstanding borrowings under our new revolving credit facility, which would not be realized if the Pony Express Project, and our sale of the Pony Express Assets, is not consummated. In addition, the failure to abandon and transfer the Pony Express Assets to Tallgrass Development would prevent Tallgrass Development from developing these assets into an oil pipeline, and would eliminate the possibility of us acquiring the Pony Express Project from Tallgrass Development in the future.

Our operations are subject to extensive regulation by federal, state and local regulatory authorities. Changes or additional regulatory measures adopted by such authorities could have a material adverse effect on our business, financial condition, and results of operations.

Our transportation and storage operations are regulated by the FERC, under the Natural Gas Act of 1938, or the NGA, the Natural Gas Policy Act of 1978, or the NGPA, and the Energy Policy Act of 2005, or EP Act 2005. The TIGT System operates under a tariff approved by the FERC that establishes rates, cost recovery mechanisms and terms and conditions of service to our customers. Generally, the FERC s authority extends to:

- rates, operating terms and conditions of service;
- the form of tariffs governing service;

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- the types of services we may offer to our customers;
- the certification and construction of new, or the expansion of existing, facilities;
- the acquisition, extension, disposition or abandonment of facilities;
- creditworthiness and credit support requirements;
- the maintenance of accounts and records;
- relationships among affiliated companies involved in certain aspects of the natural gas business;
- depreciation and amortization policies; and
- the initiation and discontinuation of services.

Interstate pipelines may not charge rates or impose terms and conditions of service that, upon review by the FERC, are found to be unjust and unreasonable or unduly discriminatory. The maximum recourse rate that we may charge for our transportation and storage services is established through the FERC s ratemaking process. The maximum applicable recourse rate and terms and conditions for service are set forth in our FERC-approved tariff.

Pursuant to the NGA, existing interstate transportation and storage rates and terms and conditions of service may be challenged by complaint and are subject to prospective change by the FERC. Additionally, rate increases and changes to terms and conditions of service proposed by a regulated interstate pipeline may be protested and such increases or changes can be delayed and may ultimately be rejected by the FERC. We currently hold authority from the FERC to charge and collect (i) recourse rates (i.e., the maximum cost-based rates an interstate pipeline may charge for its services under its tariff); (ii) discount rates which are offered by the pipeline to shippers within the cost-based maximum and minimum rate levels in effect from time to time; and (iii) negotiated rates which are fixed between the pipeline and the shipper for the contract term and do not vary with changes in the level of cost-based recourse rates, provided that the affected customers are willing to agree to such rates and that the FERC has approved the negotiated rate agreement. When capacity is available and offered for sale at other than negotiated rates, the rates (which include reservation, commodity, surcharges, fuel and gas lost and unaccounted for) are pursuant to those rates provided in our tariff, which is subject to regulatory approval and oversight. In those circumstances, regulators and customers on the TIGT System would have the right to protest or otherwise challenge the rates that we charge under a process prescribed by applicable regulations. The FERC may also initiate reviews of our rates. We may also engage in more general disputes with customers on our pipeline system regarding terms and conditions of our agreements, as well as proper interpretation and application of our tariff, among other things. Any successful challenge by a regulator or shipper in any of these matters could have a material adverse effect on our business, financial condition and results of operations.

Our gas compressor fuel costs and the cost of lost and unaccounted for gas, together referred to as Fuel Retention Factors, are recovered by retaining a fixed percentage of natural gas throughput on our transportation and storage facilities. These Fuel Retention Factors were the subject of a Section 5 proceeding initiated by the FERC that we resolved with customers by a settlement approved by the FERC in September 2011.

The FERC s jurisdiction extends to the certification and construction of interstate transportation and storage facilities, including, but not limited to, acquisitions, facility maintenance, expansions, and abandonment of facilities and services. Prior to commencing construction of significant new or existing interstate transportation and storage facilities, an interstate pipeline must obtain a certificate authorizing the construction, or file to amend its existing certificate, from the FERC. Typically, a significant expansion project requires review by a number of governmental agencies, including state and local agencies, whose cooperation is important in completing the regulatory process on schedule. Any refusal by an agency to issue authorizations or permits for one or more of these projects may mean that we will not be able to pursue these projects or that they will be constructed in a manner or with capital requirements that we did not anticipate. Such refusal or modification could materially and negatively impact the additional revenues expected from these projects.

FERC conducts audits to verify that the websites of interstate pipelines accurately provide information on the operations and availability of services on the pipeline. FERC regulations also require uniform terms and conditions for service, as set forth in agreements for transportation and storage services executed between interstate pipelines and their customers. These service agreements are required to conform, in all material respects, with the standard form of service agreements set forth in the pipeline s FERC-approved tariff. Non-conforming agreements must be filed with, and accepted by, the FERC. In the event that the FERC finds that an agreement, in whole or part, is materially non-conforming, it could reject the agreement or require us to seek modification, or alternatively require us to modify our tariff so that the non-conforming provisions are generally available to all customers.

The FERC has promulgated rules and policies covering many aspects of our business, including regulations that require us to provide firm and interruptible transportation service on an open access basis that is equal for all natural gas suppliers, provide internet access to current information about our available pipeline capacity and other relevant information, and permit pipeline shippers to release contracted transportation and storage capacity to other shippers, thereby creating secondary markets for such services. FERC regulations also restrict interstate natural gas pipelines from sharing transportation or customer information with marketing affiliates and require that interstate natural gas pipelines function independently of their marketing affiliates. As Tallgrass Midstream, LLC s operations are currently structured, Tallgrass Midstream, LLC engages in non-exempt sales for resale of natural gas in interstate commerce for which it uses transportation capacity on the TIGT System.

The FERC may not continue to pursue its approach of pro-competitive policies as it considers matters such as interstate pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity and transportation and storage facilities. Failure to comply with applicable provisions of the NGA, the NGPA, the EP Act of 2005 and certain other laws, as well as with the regulations, rules, orders, restrictions and conditions associated with these laws, could result in the imposition of administrative and criminal remedies and civil penalties of up to $1.0 million per day, per violation.

In addition, new laws or regulations or different interpretations of existing laws or regulations applicable to our pipeline system could have a material adverse effect on our business, financial condition, results of operations and prospects. We may face challenges to our rates or terms of service in the future. Any successful challenge could materially adversely affect our future earnings and cash flows.

If the tariff governing the services we provide is successfully challenged, we could be required to reduce our tariff rates, which could have a material adverse effect on our business, results of operations, financial condition and ability to make quarterly cash distributions to our unitholders.

Any of our shippers, the FERC, or other interested stakeholders, such as state regulatory agencies, may challenge the maximum recourse rates or the terms and conditions of service included in our tariff. We do not have an agreement in place that would prohibit these parties from challenging our tariff. If any challenge were successful, among other things, the rates that we charge on our systems could be reduced. For example, we were subject to a Section 5 proceeding initiated by our shippers relating to our Fuel Retention Factors, which generally are recovered by retaining a fixed percentage of natural gas throughput on our transportation and storage facilities. We resolved these issues with customers by a settlement approved by the FERC in September 2011, which resulted in a 27% reduction in the Fuel Retention Factors billed to shippers effective June 1, 2011, causing a decrease in transportation and storage revenue. The Section 5 Settlement also provided for a second stepped reduction, resulting in a total 30% reduction in the Fuel Retention Factors billed to shippers and effective January 1, 2012, for certain segments of the former Pony Express pipeline system. Successful challenges could have a material adverse effect on our business, results of operations, financial condition and ability to make quarterly cash distributions to our unitholders.

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We are exposed to the creditworthiness and performance of our customers, suppliers and contract counterparties, and any material nonpayment or nonperformance by one or more of these parties could adversely affect our financial and operating results.

Although we attempt to assess the creditworthiness of our customers, suppliers and contract counterparties, there can be no assurance that our assessments will be accurate or that there will not be a rapid or unanticipated deterioration in their creditworthiness, which may have an adverse impact on our business, results of operations, financial condition and ability to make cash distributions to our unitholders. In addition, our long-term firm transportation and storage contracts obligate our customers to pay demand charges regardless of whether they transport or store natural gas on our facilities, except when we are unable to schedule the customer s nomination for service due to capacity constraints caused by maintenance or a force majeure event lasting more than 10 days. As a result, during the term of our long-term firm transportation and storage contracts and absent an event of force majeure, our revenues will generally depend on our customers financial condition and their ability to pay rather than upon the amount of natural gas transported. Further, our contract counterparties may not perform or adhere to our existing or future contractual arrangements. Any material nonpayment or nonperformance by our contract counterparties due to inability or unwillingness to perform or adhere to contractual arrangements could have an adverse impact on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

The procedures and policies we use to manage our exposure to credit risk, such as credit analysis, credit monitoring and, in some cases, requiring credit support, cannot fully eliminate counterparty credit risks. To the extent our procedures and policies prove to be inadequate, our financial and operational results may be negatively impacted.

Some of our counterparties may be highly leveraged or have limited financial resources and will be subject to their own operating and regulatory risks. Even if our credit review and analysis mechanisms work properly, we may experience financial losses in our dealings with such parties. In addition, volatility in commodity prices might have an impact on many of our counterparties, which, in turn, could have a negative impact on their ability to meet their obligations to us and may also increase the magnitude of these obligations.

Any material nonpayment or nonperformance by our counterparties could require us to pursue substitute counterparties for the affected operations, reduce operations or provide alternative services. There can be no assurance that any such efforts would be successful or would provide similar financial and operational results.

Any significant decrease in available supplies of natural gas in our areas of operation, or redirection of existing natural gas supplies to other markets, could adversely affect our business and operating results.

Our business is dependent on the continued availability of natural gas production and reserves. Production from existing wells and natural gas supply basins with access to our transportation, storage and processing facilities will naturally decline over time. The amount of natural gas reserves underlying these wells may also be less than anticipated, and the rate at which production from these reserves declines may be greater than anticipated. Accordingly, to maintain or increase the contracted capacity or the volume of natural gas transported, stored and treated on our systems and cash flows associated therewith, our customers must continually obtain adequate supplies of natural gas.

However, the development of additional natural gas reserves requires significant capital expenditures by others for exploration and development drilling and the installation of production, storage, transportation and other facilities that permit natural gas to be produced and delivered to our transportation, storage and processing facilities. In addition, low prices for natural gas, regulatory limitations, including environmental regulations, or the lack of available capital for these projects could have a material adverse effect on the development and production of additional reserves, as well as storage, pipeline transportation, and import and export of natural gas supplies. Furthermore, competition for natural gas supplies to serve other markets could reduce the amount of natural gas supply available for our customers. Accordingly, to maintain or increase the contracted capacity or the volume of natural gas transported on our systems and cash flows associated with our operations, our customers must compete with others to obtain adequate supplies of natural gas.

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If new supplies of natural gas are not obtained to replace the natural decline in volumes from existing supply basins, if natural gas supplies are diverted to serve other markets, or if environmental regulators restrict new natural gas drilling, the overall demand for transportation, storage and processing services on our systems would decline, which could have a material adverse effect on our ability to renew or replace our current customer contracts when they expire and on our business, financial condition, results of operations and ability to make quarterly cash distributions to our unitholders.

Constructing new assets subjects us to risks of project delays, cost overruns and lower-than-anticipated volumes of natural gas once a project is completed. Our operating cash flows from our capital projects may not be immediate or meet our expectations.

One of the ways we may grow our business is by constructing additions or modifications to our existing facilities. We also may construct new facilities, either near our existing operations or in new areas. For example, we are currently undergoing an expansion of our Casper and Douglas plants to increase processing capacity and upgrade compression. Construction projects require significant amounts of capital and involve numerous regulatory, environmental, political, legal and operational uncertainties, many of which are beyond our control. These projects also involve numerous economic uncertainties, including the impact of inflation on project costs and the availability of required resources. For example, we currently are party to a lawsuit in Fremont County, Wyoming arising out of the construction of the West Frenchie Draw amine treating plant. For more information, please read Item 1. Legal Proceedings.

We may be unable to complete construction projects on schedule, at the budgeted cost, or at all, which could have a material adverse effect on our business and results of operations. Moreover, we may not receive any material increase in operating cash flow from a project for some time. For instance, if we expand a pipeline or processing facility, the construction expenditures may occur over an extended period of time, yet we will not receive any material increases in cash flow until the project is completed and fully operational. In addition, our cash flow from a project may be delayed or may not meet our expectations. Our project specifications and expectations regarding project cost, timing, asset performance, investment returns and other matters usually rely in part on the expertise of third parties such as engineers, technical experts and construction contractors. These estimates may prove to be inaccurate because of numerous operational, technological, economic and other uncertainties.

We rely in part on estimates from producers regarding of the timing and volume of anticipated natural gas production. Production estimates are subject to numerous uncertainties, all of which are beyond our control. These estimates may prove to be inaccurate, and new facilities may not attract sufficient volumes to achieve our expected cash flow and investment return.

Our success depends on the supply and demand for natural gas.

The success of our business is in many ways impacted by the supply and demand for natural gas. For example, our business can be negatively impacted by sustained downturns in supply and demand for natural gas in the markets that we serve, including reductions in our ability to renew contracts on favorable terms and to construct new infrastructure. One of the major factors that will impact natural gas demand will be the potential growth of the demand for natural gas in the power generation market, particularly driven by the speed and level of existing coal-fired power generation that is replaced with natural gas-fired power generation. One of the major factors impacting natural gas supplies has been the significant growth in unconventional sources such as shale plays. The supply and demand for natural gas and therefore the future rate of growth of our business will depend on these and many other factors outside of our control, including, but not limited to:

- adverse changes in general global economic conditions;
- adverse changes in domestic regulations;

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- technological advancements that may drive further increases in production and reduction in costs of developing natural gas shales;
- the price and availability of other forms of energy;
- prices for natural gas;
- increased costs to explore for, develop, produce, gather, process and transport natural gas;
- weather conditions, seasonal trends and hurricane disruptions;
- the nature and extent of, and changes in, governmental regulation, for example greenhouse gas legislation and taxation; and
- perceptions of customers on the availability and price volatility of our services and natural gas prices, particularly customers perceptions on the volatility of natural gas prices over the longer-term.

We are subject to numerous hazards and operational risks.

Our operations are subject to all the risks and hazards typically associated with the transportation, storage and processing of natural gas. These operating risks include, but are not limited to:

- damage to pipelines, facilities, equipment and surrounding properties caused by hurricanes, earthquakes, tornadoes, floods, fires or other adverse weather conditions and other natural disasters and acts of terrorism;
- inadvertent damage from construction, vehicles, farm and utility equipment;
- uncontrolled releases of natural gas and other hydrocarbons;
- leaks, migrations or losses of natural gas as a result of the malfunction of equipment or facilities;
- outages at our processing facilities;
- ruptures, fires and explosions; and
- other hazards that could also result in personal injury and loss of life, pollution and other environmental risks, and suspension of operations.

For example, on May 4, 2013, we experienced a release of natural gas from a segment of pipeline in Kimball County, Nebraska resulting in damage to a small section of the TIGT pipeline. And, on June 13, 2013, a failure occurred on a small portion of an approximately 32.98 mile segment of the TIGT pipeline near Torrington, Wyoming, resulting in a release of natural gas.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage. The location of certain segments of our pipeline system in or near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas could increase the level of damages resulting from these risks. Despite the precautions we take, events such as those described above could cause considerable harm to people or property, could result in loss of service available to customers, and could have a material adverse effect on our financial condition and results of operations. In addition, maintenance, repair and remediation activities could result in service interruptions on segments of our systems or alter the operational profile of our systems. Potential impacts arising from these service interruptions or operational profile changes on segments of our systems could include, among others, limitations on our ability to satisfy customer requirements, obligations to provide reservation charge credits to customers in times of constrained capacity, and solicitation of existing customers by others for potential new projects that would compete directly with existing services.

We could be required by regulatory authorities to test or undertake modifications to our systems, operations or both that could result in a material adverse impact on our business, financial condition and results of operations. For example, we received a Corrective Action Order from PHMSA on June 19, 2013 directing us to take certain investigative, testing and corrective measures with regard to the segment of the TIGT pipeline that failed on June 13, 2013. We intend to request a formal hearing to discuss these matters with PHMSA. Such actions, including those required by PHMSA, could materially and adversely impact our ability to meet contractual obligations and retain customers, with a resulting material adverse impact on our business and results of operations, and could also limit or prevent our ability to make quarterly cash distributions to our unitholders. Some or all of our costs arising from these operational risks may not be recoverable under insurance, contractual indemnification or increases in rates charged to our customers.

Our insurance coverage may not be adequate.

We are not fully insured against all risks inherent to our business, including environmental accidents that might occur. For example, we do not maintain business interruption insurance in the type and amount to cover all possible risks of loss. In addition, we do not carry insurance for certain environmental exposures, including but not limited to potential environmental fines and penalties, business interruption, named windstorm or hurricane exposures and, in limited circumstances, certain political risk exposures. Further, in the event there is a total or partial loss of our pipeline system and/or processing facilities, any insurance proceeds that we may receive in respect thereof may not be sufficient in any particular situation to effect a restoration of our pipeline system and/or processing facilities to the condition that existed prior to such loss. In addition, we do not have insurance coverage on the legal proceedings described in Item 1. Legal Proceedings. The occurrence of any operating risks not fully covered by insurance could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Furthermore, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates, and we may elect to self-insure a portion of our asset portfolio. As a result of market conditions, premiums and deductibles for certain types of insurance policies may substantially increase, and in some instances, certain types of insurance could become unavailable or available only for reduced amounts of coverage. Accordingly, any insurance coverage we do obtain may contain large deductibles or fail to cover certain hazards or cover all potential losses.

Our pipeline integrity program may impose significant costs and liabilities on us, while increased regulatory requirements relating to the integrity of our pipeline system may require us to make additional capital and operating expenditures to comply with such requirements.

We are subject to extensive laws and regulations related to pipeline integrity. There are, for example, federal requirements set by PHMSA for pipeline companies in the areas of pipeline design, construction, and testing, the qualification of personnel and the development of operations and emergency response plans. The rules require pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines and take measures to protect pipeline segments located in what the rules refer to as High Consequence Areas, or HCAs.

Our interstate pipeline operations are subject to pipeline safety regulations administered by PHMSA. These regulations, among other things, include requirements to monitor and maintain the integrity of our pipeline system and determine the pressures at which our pipeline system can operate. The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, or the Pipeline Safety Act of 2011, enacted January 3, 2012, amends the Pipeline Safety Improvement Act of 2002, or the Pipeline Safety Act of 2002, in a number of significant ways, including:

- reauthorizing funding for federal pipeline safety programs, increasing penalties for safety violations and establishing additional safety requirements for newly constructed pipelines;

- requiring PHMSA to adopt appropriate regulations within two years and requiring the use of automatic or remote-controlled shutoff valves on new or rebuilt pipeline facilities;

- requiring operators of pipelines to verify maximum allowable operating pressure and report exceedances within five days; and

- requiring studies of certain safety issues that could result in the adoption of new regulatory requirements for new and existing pipelines, including changes to integrity management requirements for HCAs, and expansion of those requirements to areas outside of HCAs.

PHMSA published an advanced notice of proposed rulemaking in August 2011 to solicit comments on the need for changes to its safety regulations, including whether to revise integrity management requirements. On August 13, 2012, PHMSA published rules to update pipeline safety regulations to reflect provisions included in the Pipeline Safety Act of 2011, including increasing maximum civil penalties from $0.1 million to $0.2 million per violation per day of violation and from $1.0 million to $2.0 million as a maximum amount for a related series of violations as well as changing PHMSA s enforcement process.

The ultimate costs of compliance with the integrity management rules are difficult to predict. The majority of the costs to comply with the rules are associated with pipeline integrity testing and the repairs found to be necessary. Changes such as advances of in-line inspection tools, identification of additional threats to a pipeline s integrity and changes to the amount of pipe determined to be located in HCAs or expansion of integrity management requirements to areas outside of HCAs can have a significant impact on the costs to perform integrity testing and repairs. We plan to continue our pipeline integrity testing programs to assess and maintain the integrity of our existing and future pipelines as required by the DOT rules. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

Further, additional laws, regulations and policies that may be enacted or adopted in the future or a new interpretation of existing laws and regulations could significantly increase the amount of these expenditures. For example, PHMSA issued an Advisory Bulletin in May 2012 which advised pipeline operators that they must have records to document the maximum allowable operating pressure for each section of their pipeline and that the records must be traceable, verifiable and complete. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing or modifying or replacing facilities to meet the demands of verifiable pressures, could significantly increase our costs. Additionally, failure to locate such records or verify maximum pressures could require us to operate at reduced pressures, which would reduce available capacity on our pipeline system. There can be no assurance as to the amount or timing of future expenditures required to comply with pipeline integrity regulation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions could have a material adverse effect on our business, financial position, results of operations and prospects.

In addition, we may be subject to enforcement actions and penalties for failure to comply with pipeline regulations. On August 29, 2012, PHMSA notified Tallgrass Interstate Gas Transmission, LLC that a report from an audit conducted in 2010 indicated a probable violation for failing to perform a periodic review of personnel responses to certain abnormal operations. Specifically, PHMSA cited to the operation of a relief valve on March 3, 2010. If we are not able to successfully defend this alleged violation, Tallgrass Interstate Gas Transmission, LLC may be required to change its operating procedures, which could increase operating costs. Tallgrass Interstate Gas Transmission, LLC responded to the notice of probable violation and requested a hearing in a response filed with PHMSA on October 1, 2012. A hearing was held on January 15, 2013. The matter is ongoing.

Climate change regulation at the federal, state or regional levels could result in increased operating and capital costs for us.

Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of natural gas, are examples of greenhouse gases, or GHGs. Various laws and regulations exist, or are under development that

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seek to regulate the emission of such GHGs, including United States Environmental Protection Agency, or the EPA, programs to control GHG emissions and state actions to develop statewide or regional programs. In recent years, the U.S. Congress has considered, but not adopted, legislation to reduce emissions of GHGs.

The EPA published in December 2009 its findings that emissions of GHGs present an endangerment to human health and the environment. Pursuant to this endangerment finding and other rulemakings and interpretations, the EPA concluded that stationary sources would become subject to federal permitting requirements under the Clean Air Act, or the CAA, starting in 2011. In 2010, the EPA issued a final rule, known as the Tailoring Rule, that defines regulatory emission thresholds at which certain new and modified stationary sources are subject to permitting and other requirements for GHG emissions under the CAA s Prevention of Significant Deterioration, or PSD, and Title V programs. The EPA has indicated in rulemakings that it may reduce the current regulatory thresholds for GHGs, making additional sources subject to PSD permitting requirements. However, in July 2012, the EPA declined to lower the applicability thresholds to allow the GHG regulations to apply to additional, smaller sources. The EPA s determination was to allow states additional time to implement existing GHG regulations, as opposed to an EPA determination that regulation was unnecessary. As such, the EPA may still lower the threshold for GHG permitting in the future, which may affect our facilities. Some of our facilities emit GHGs in excess of the currently-applicable Tailoring Rule thresholds and have been required to obtain a Title V Permit that reflects this potential to emit GHGs. Although these existing facilities are not currently required to obtain a PSD permit containing enforceable limits on GHG emissions, any future modifications with a potential to emit GHGs above the applicable regulatory thresholds at the time of the application would require us to obtain a PSD permit containing enforceable limits on GHG emissions.

Additional direct regulation of GHG emissions in our industry may be implemented under other CAA programs, including the New Source Performance Standards, or NSPS, program. The EPA has already proposed to regulate GHG emissions from certain electric generating units under the NSPS program. While these proposed regulations for electric generating units would not apply to our operations, the EPA may propose to regulate additional sources under the NSPS program. In addition, in 2009, the EPA published a final rule requiring that specified large GHG emissions sources annually report the GHG emissions for the preceding year in the United States, beginning in 2011 for emissions occurring in 2010. In 2010, the EPA published a final rule expanding its existing GHG emissions reporting rule for petroleum and natural gas facilities, including natural gas transportation compression facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. The rule, which went into effect in December 2010, requires reporting of GHG emissions by regulated facilities to the EPA on an annual basis. Reporting was first required in 2012 for emissions during 2011. Some of our facilities are required to report under this rule, and operational and/or regulatory changes could require additional facilities to comply with GHG emissions reporting requirements.

At the state level, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of GHGs, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs. Many of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal. Depending on the particular program, we could be required to purchase and surrender emission allowances.

Because our operations, including our compressor stations and processing facilities, emit various types of GHGs, primarily methane and carbon dioxide, new legislation or regulation could increase our costs related to operating and maintaining our facilities, and could delay future permitting. Depending on the particular new law, regulation or program adopted, we could be required to incur capital expenditures for installation of new emission controls on our compressor stations and processing facilities, acquire and surrender allowances for our GHG emissions, pay taxes related to our GHG emissions and administer and manage a GHG emissions program. We are not able at this time to estimate such increased costs; however, they could be significant. While we may be able to

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include some or all of such increased costs in the rates charged by our pipeline system, such recovery of costs is uncertain in all cases and may depend on events beyond our control including the outcome of future rate proceedings before the FERC and the provisions of any final legislation or other regulations. Similarly, while we may be able to recover some or all of such increased costs in the rates charged by our processing facilities, such recovery of costs is uncertain and may depend on the terms of our contracts with our customers. Any of the foregoing could have a material adverse effect on our business, financial position, results of operations and prospects. To the extent financial markets view climate change and greenhouse gas emissions as a financial risk, this could materially and adversely impact our cost of and access to capital. Legislation or regulations that may be adopted to address climate change, or incentives to conserve energy or use alternative energy sources, could also affect the markets for our services by making natural gas products less desirable than competing sources of energy.

Our operations are subject to governmental laws and regulations relating to the protection of the environment, which may expose us to significant costs, liabilities and expenditures that could exceed our current expectations.

Substantial costs, liabilities, delays and other significant issues related to environmental laws and regulations are inherent in natural gas transportation, storage and processing operations, and as a result, we may be required to make substantial expenditures that could exceed current expectations. Our operations are subject to extensive federal, state, and local laws and regulations governing health and safety aspects of our operations, environmental protection, including the discharge of materials into the environment, and the security of chemical and industrial facilities. These laws include, but are not limited to, the following:

- CAA and analogous state laws, which impose obligations related to air emissions;
- Clean Water Act, or CWA, and analogous state laws, which regulate discharge of pollutants contained in wastewater and storm water from our facilities to state and federal waters, including wetlands;
- Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, and analogous state laws, which regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent wastes for disposal;
- Resource Conservation and Recovery Act, or RCRA, and analogous state laws, which impose requirements for the handling and discharge of hazardous and nonhazardous solid waste from our facilities;
- Occupational Safety and Health Act, or OSHA, which establishes workplace standards for the protection of the health and safety of employees, including the implementation of hazard communications programs designed to inform employees about hazardous substances in the workplace, potential harmful effects of these substances, and appropriate control measures;
- The National Environmental Policy Act, or NEPA, which requires federal agencies to evaluate major agency actions having the potential to significantly impact the environment and which may require the preparation of Environmental Assessments and more detailed Environmental Impact Statements that may be made available for public review and comment;
- The Migratory Bird Treaty Act, which implements various treaties and conventions between the United States and certain other nations for the protection of migratory birds and, pursuant to which the taking, killing or possessing of migratory birds is unlawful without a permit, thereby potentially requiring the implementation of operating restrictions or a temporary, seasonal, or permanent ban in affected areas;
- Endangered Species Act, or ESA, and analogous state laws, which seek to ensure that activities do not jeopardize endangered or threatened animals, fish and plant species, nor destroy or modify the critical habitat of such species; and

Oil Pollution Act of 1990, or OPA, and analogous laws, which imposes liability for discharges of oil into waters of the United States and requires facilities which could be reasonably expected to discharge oil into waters of the United States to maintain and implement appropriate spill contingency plans.

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Various governmental authorities, including the EPA, the U.S. Department of the Interior, the U.S. Department of Homeland Security, and analogous state and local agencies have the power to enforce compliance with these laws and regulations and the permits and related plans issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws, regulations, permits, plans and agreements may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, the imposition of stricter conditions on or revocation of permits, the issuance of injunctions limiting or preventing some or all of our operations, and delays in granting permits.

There is inherent risk of the incurrence of environmental costs and liabilities in our business, some of which may be material, due to our handling of the products we transport and store, air emissions related to our operations, historical industry operations, and waste disposal practices, and the prior use of flow meters and manometers containing mercury. Joint and several, strict liability may be incurred without regard to fault under certain environmental laws and regulations, including but not limited to CERCLA, RCRA and analogous state laws, for the remediation of contaminated areas and in connection with spills or releases of materials associated with natural gas and wastes on, under, or from our properties and facilities. We are currently conducting remediation at several sites to address contamination. For 2013, we have budgeted approximately $372,000 for these ongoing environmental remediation projects. Private parties, including but not limited to the owners of properties through which our pipeline system passes and facilities where our wastes are taken for reclamation or disposal, may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws, regulations and permits issued thereunder, or for personal injury or property damage arising from our operations. Some sites at which we operate are located near current or former third-party hydrocarbon storage and processing or natural gas operations or facilities, and there is a risk that contamination has migrated from those sites to ours that could result in remedial action. In addition, increasingly strict laws, regulations and enforcement policies could materially increase our compliance costs and the cost of any remediation that may become necessary. Our insurance does not cover all environmental risks and costs and may not provide sufficient coverage if an environmental claim is made against us.

In March 2010, the EPA announced its National Enforcement Initiatives for 2011 to 2013, which included the addition of Energy Extraction Activities to its enforcement priorities list. To address its concerns regarding the pollution risks raised by new techniques for oil and gas extraction and coal mining, the EPA is developing an initiative to ensure that energy extraction activities are complying with federal environmental requirements and increasing its inspection and evaluation frequency. On January 28, 2013, the EPA issued a notice seeking comment on whether to extend the current National Enforcement Initiatives, including the initiative related to Energy Extraction Activities, for the next three years. We cannot predict what the results of the current initiative or any future initiative will be, or whether federal, state or local laws or regulations will be enacted in this area. If new regulations are imposed related to oil and gas extraction, the volumes of natural gas that we transport and/or process could decline and our results of operations could be materially adversely affected.

Our business may be materially and adversely affected by changed regulations and increased costs due to stricter pollution control requirements or liabilities resulting from non-compliance with required operating or other regulatory permits or plans developed thereunder. Also, we might not be able to obtain or maintain from time to time all required environmental regulatory approvals for our operations, or may have to implement contingencies or conditions in order to obtain such approvals. If there is a delay in obtaining any required environmental regulatory approvals, or if we fail to obtain and comply with them, the operation or construction of our facilities could be prevented or become subject to additional costs, resulting in potentially material adverse consequences to our business, financial condition, results of operations and cash flows.

We are also generally responsible for all liabilities associated with the environmental condition of our facilities and assets, whether acquired or developed, regardless of when the liabilities arose and whether they are known or unknown. In connection with certain acquisitions and divestitures, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses, which may not be covered by insurance. In addition, the steps we could be required to take to bring certain facilities into compliance could be prohibitively expensive, and we might be required to shut down, divest or alter the operation of those facilities, which might cause us to incur losses.

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We have agreed to a number of conditions in our environmental permits and associated plans, approvals and authorizations that require the implementation of environmental habitat restoration, enhancement and other mitigation measures that involve, among other things, ongoing maintenance and monitoring. Governmental authorities may require, and community groups and private persons may seek to require, additional mitigation measures in the future to further protect ecologically sensitive areas where we currently operate, and would operate if our facilities are extended or expanded, or if we construct new facilities, and we are unable to predict the effect that any such measures would have on our business, financial position, results of operations or prospects.

Further, such existing laws and regulations may be revised or new laws or regulations may be adopted or become applicable to us. In addition to potential GHG regulations, there may also be potential regulations under the NSPS and/or the maximum available control technology standard that may affect us. The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. There can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be materially different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and prospects.

Increased regulation of hydraulic fracturing and other natural gas processing operations could affect our operations and result in reductions or delays in natural gas production by our customers, which could have a material adverse impact on our revenues.

A portion of our customers natural gas production is developed from unconventional sources, such as shales, that require hydraulic fracturing as part of the completion process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into shale formations to stimulate gas production. Hydraulic fracturing is currently exempt from federal regulation pursuant to the federal Safe Drinking Water Act, or the SDWA (except when the fracturing fluids or propping agents contain diesel fuels), because hydraulic fracturing is excluded from the SDWA definition of underground injection and therefore is not subject to permitting and federal regulatory control pursuant to SDWA. However, public concerns have been raised related to its potential environmental impact. Additional federal, state and local laws and regulations to more closely regulate hydraulic fracturing have been considered and, in some cases, adopted and implemented. For example, from time to time, legislation to further regulate hydraulic fracturing has been proposed in Congress, including repeal of the SDWA exemption for hydraulic fracturing, as well as to require disclosure for chemicals used in hydraulic fracturing. An EPA investigation requested by a committee of the House of Representatives to assess the potential environmental effects of hydraulic fracturing on drinking water and groundwater is underway, with a first progress report outlining work currently underway by the agency released on December 21, 2012 and a final draft report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review by 2014. Reports prepared by the U.S. Department of Energy s Shale Gas Subcommittee could also lead to further restrictions on hydraulic fracturing. In addition, in October 2011, EPA announced its intention to propose regulations by 2014 under the CWA regarding wastewater discharges from hydraulic fracturing and other gas production and, in November 2011, EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act, or the TSCA, to require companies to disclose information regarding the chemicals used in hydraulic fracturing.

Apart from federal legislation and EPA regulations, other federal agencies and states have proposed or adopted legislation or regulations restricting hydraulic fracturing. On May 4, 2012, the U.S. Department of Interior issued a draft proposed rule requiring the disclosure of chemicals used during hydraulic fracturing, as well as drilling plans, water management, and wastewater disposal, on federal and Indian lands but, more recently, on January 18, 2013 a spokesperson for the Department of Interior announced plans to issue a new draft rule in 2013. Moreover, some state and local authorities have considered or imposed new laws and rules related to hydraulic fracturing, including additional permit requirements, operational restrictions, chemical disclosure obligations and temporary or permanent bans on hydraulic fracturing in certain jurisdictions or in environmentally sensitive areas. For example, Wyoming has imposed regulations regarding disclosure of information regarding chemicals in well stimulation operations. We cannot predict whether any additional federal, state or local laws or regulations will be enacted in this area and if so, what their provisions would be. If additional levels of reporting, regulation or permitting moratoria were required or imposed related to hydraulic fracturing, the volumes of natural gas that we transport could decline and our results of operations could be materially and adversely affected.

In addition, new EPA rules that became effective on October 15, 2012 establish new air emission controls for oil and natural gas production, pipelines and processing operations. For new or reworked hydraulically-fractured gas wells, the rules require the control of emissions through flaring or reduced emission (or green) completions until 2015, when the rules require the use of green completions by all such wells except wildcat (exploratory) and delineation gas wells and low reservoir pressure non-wildcat and non-delineation gas wells. The rules also establish specific new requirements regarding emissions from wet seal and reciprocating compressors at production facilities, gathering systems, boosting facilities and onshore natural gas processing plants, effective October 15, 2012, and from pneumatic controllers and storage vessels at production facilities, gathering systems, boosting facilities and onshore natural gas processing plants, effective October 15, 2013. In addition, the rules revise existing requirements for volatile organic compound emissions from equipment leaks at onshore natural gas processing plants by lowering the leak definition for valves from 10,000 parts per million to 500 parts per million and requiring the monitoring of connectors, pumps, pressure relief devices and open-ended lines, effective October 15, 2012. These rules may therefore require a number of modifications to our and our customers operations, including the installation of new equipment to control emissions. Compliance with such rules could result in additional costs, including increased capital expenditures and operating costs, for us and our customers, which could have a material adverse effect on our business. In October 2012, several challenges to EPA s rules were filed by various parties, including environmental groups and industry associations. In a January 1, 2013 unopposed motion to hold this litigation in abeyance, EPA indicated that it may reconsider some aspects of the rule. Depending on the outcome of such proceedings, the rules may be modified or rescinded or EPA may issue new rules; the costs of compliance with any modified or newly issue rules cannot be predicted.

We are exposed to costs associated with lost and unaccounted for volumes.

A certain amount of natural gas is naturally lost in connection with its transportation across a pipeline system, and under our contractual arrangements with our customers we are entitled to retain a specified volume of natural gas in order to compensate us for such lost and unaccounted for volumes as well as the natural gas used to run our compressor stations, which we refer to as fuel usage. The level of fuel usage and lost and unaccounted for volumes on our pipeline system may exceed the natural gas volumes retained from our customers as compensation for our fuel usage and lost and unaccounted for volumes pursuant to our contractual agreements and it will be necessary to purchase natural gas in the market to make up for the difference, which exposes us to commodity price risk. Future exposure to the volatility of natural gas prices as a result of gas imbalances could have a material adverse effect on our business, financial condition, results of operations and ability to make quarterly cash distributions to our unitholders.

Approximately one-third of our contracted transportation and storage firm capacity is provided under long-term, fixed price negotiated rate contracts that are not subject to adjustment, even if our cost to perform such services exceeds the revenues received from such contracts, and, as a result, our costs could exceed our revenues received under such contracts.

It is possible that costs to perform services under our negotiated rate contracts will exceed the negotiated rates. If this occurs, it could decrease the cash flow realized by our systems and, therefore, the cash we have available for distributions to our unitholders. Under FERC policy, a regulated service provider and a customer may mutually agree to sign a contract for service at a negotiated rate, which is fixed between the pipeline and the shipper for the contract term and does not vary with changes in the level of cost-based recourse rates , provided that the affected customer is willing to agree to such rates and that the FERC has approved the negotiated rate agreement. Approximately one-third of our contracted transportation firm capacity is currently subscribed under such negotiated rate contracts. These negotiated rate contracts are not generally subject to adjustment for increased costs which could be caused by inflation or other factors relating to the specific facilities being used to perform the services. Any shortfall of revenue, representing the difference between recourse rates (if higher) and negotiated rates, under current FERC policy is generally not recoverable from other shippers.

Any significant and prolonged change in or stabilization of natural gas prices could have a negative impact on our natural gas storage business.

Historically, natural gas prices have been seasonal and volatile, which has enhanced demand for our storage services. The natural gas storage business has benefited from significant price fluctuations resulting from seasonal price sensitivity, which impacts the level of demand for our services and the rates we are able to charge for such services. On a system-wide basis, natural gas is typically injected into storage between April and October when natural gas prices are generally lower and withdrawn during the winter months of November through March when natural gas prices are typically higher. However, the market for natural gas may not continue to experience volatility and seasonal price sensitivity in the future at the levels previously seen. If volatility and seasonality in the natural gas industry decrease, because of increased production capacity or otherwise, then demand for our storage services and the prices that we will be able to charge for those services may decline.

In addition to volatility and seasonality, an extended period of high natural gas prices would increase the cost of acquiring base gas and likely place upward pressure on the costs of associated storage expansion activities. Alternatively, an extended period of low natural gas prices could adversely impact storage values for some period of time until market conditions adjust. These commodity price impacts could have a negative impact on our business, financial condition, results of operations and ability to make distributions.

Certain portions of our transportation, storage and processing facilities have been in service for several decades. There could be unknown events or conditions or increased maintenance or repair expenses and downtime associated with our facilities that could have a material adverse effect on our business and results of operations.

Significant portions of our transportation, storage and processing systems have been in service for several decades. The age and condition of our facilities could result in increased maintenance or repair expenditures, and any downtime associated with increased maintenance and repair activities could materially reduce our revenue. Any significant increase in maintenance and repair expenditures or loss of revenue due to the age or condition of our facilities could adversely affect our business and results of operations and our ability to make cash distributions to our unitholders.

Certain of our processing customers require credit support, some of which are currently provided through parent guarantees provided by Tallgrass Development. We may incur additional costs associated with replacing those guarantees.

Certain of our processing customers require credit support, and some of this support is currently in the form of parent guarantees provided by Tallgrass Development, as the previous owner of TMID. To the extent we are required to replace such guarantees with substitute credit support, we may incur additional costs, including costs associated with issuing letters of credit.

Restrictions in our new credit facility could adversely affect our business, financial condition, results of operations and ability to make quarterly cash distributions to our unitholders.

We entered into a new credit facility in connection with the closing of our initial public offering. Our new credit facility limits our ability to, among other things:

- incur or guarantee additional debt;
- redeem or repurchase units or make distributions under certain circumstances;
- make certain investments and acquisitions;
- incur certain liens or permit them to exist;
- enter into certain types of transactions with affiliates;
- merge or consolidate with another company; and
- transfer, sell or otherwise dispose of assets.

Our new credit facility also contains covenants requiring us to maintain certain financial ratios. Our ability to meet those financial ratios and tests can be affected by events beyond our control, and we cannot assure you that we will meet those ratios and tests.

The provisions of our new credit facility may affect our ability to obtain future financing and pursue attractive business opportunities and our flexibility in planning for, and reacting to, changes in business conditions. In addition, a failure to comply with the provisions of our new credit facility could result in a default or an event of default that could enable our lenders to declare the outstanding principal of that debt, together with accrued and unpaid interest, to be immediately due and payable. If the payment of our debt is accelerated, our assets may be insufficient to repay such debt in full, and our unitholders could experience a partial or total loss of their investment.

Our future debt levels may limit our flexibility to obtain financing and to pursue other business opportunities.

Our level of debt could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- our funds available for operations, future business opportunities and distributions to unitholders will be reduced by that portion of our cash flow required to make interest payments on our debt;
- we may be more vulnerable to competitive pressures or a downturn in our business or the economy generally; and

our flexibility in responding to changing business and economic conditions may be limited.

Our ability to service our debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service our current or future indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets or seeking additional equity capital. We may not be able to effect any of these actions on satisfactory terms or at all.

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Increases in interest rates could adversely impact demand for our storage capacity, our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

There is a financing cost for our customers to store natural gas in our storage facilities. That financing cost is impacted by the cost of capital or interest rate incurred by the customer in addition to the commodity cost of the natural gas in inventory. Absent other factors, a higher financing cost adversely impacts the economics of storing natural gas for future sale. As a result, a significant increase in interest rates could adversely affect the demand for our storage capacity independent of other market factors.

In addition, interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. As with other yield-oriented securities, our unit price is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

The amount of cash we have available for distribution to unitholders depends primarily on our cash flow rather than on our profitability, which may prevent us from making distributions, even during periods in which we record net income.

The amount of cash we have available for distribution depends primarily upon our cash flow and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes and may not make cash distributions during periods when we record net earnings for financial accounting purposes.

The lack of diversification of our assets and geographic locations could adversely affect our ability to make distributions to our common unitholders.

We rely primarily on revenues generated from natural gas transportation, storage and processing systems that we own, which are primarily located in the Rocky Mountain and Midwest regions of the United States. Due to our lack of diversification in assets and geographic location, an adverse development in these businesses or our areas of operations, including adverse developments due to catastrophic events, weather, regulatory action and decreases in demand for natural gas, could have a significantly greater impact on our results of operations and cash available for distribution to our common unitholders than if we maintained more diverse assets and locations.

We do not own most of the land on which the TIGT System and Midstream Facilities are located, which could disrupt our operations and subject us to increased costs.

We do not own most of the land on which the TIGT System and Midstream Facilities have been constructed, and we are therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights-of-way, if such rights-of-way lapse or terminate or if our facilities are not properly located within the boundaries of such rights-of-way. For example, the West Frenchie Draw treating facility is located on land leased from the Wyoming Board of Land Commissioners pursuant to a contract that can be terminated at any time. Although many of these rights are perpetual in nature, we occasionally obtain the right to construct and operate pipelines on other owners land for a specific period of time. If we were to be unsuccessful in renegotiating rights-of-way, we may need to exercise TIGT System s eminent domain authority and might incur increased costs to maintain the TIGT System, which could have a material adverse effect on our business, results of operations, financial condition and ability to make distributions to our unitholders. In addition, we are subject to the possibility of increased costs under our rental agreements with landowners, primarily through rental increases and renewals of expired agreements.

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Some rights-of-way for the TIGT System and other real property assets are shared with other pipeline systems and other assets owned by third parties. We or owners of the other pipeline systems may not have commenced or concluded eminent domain proceedings for some rights-of-way. In some instances, lands over which rights-of-way have been obtained are subject to prior liens which have not been subordinated to the right-of-way grants.

The TIGT System has federal eminent domain authority. Regardless, we must compensate landowners for the use of their property, which may include any loss of value to the remainder of their property not being used by us, which are sometimes referred to as severance damages . Severance damages are often difficult to quantify and their amount can be significant. In eminent domain actions, such compensation may be determined by a court. Our inability to exercise the power of eminent domain could negatively affect our business if we were to lose the right to use or occupy the property on which our pipeline system is located.

Our operations are dependent on our rights and ability to receive or renew the required permits and other approvals from governmental authorities and other third parties.

Performance of our operations requires that we obtain and maintain numerous environmental and land use permits and other approvals authorizing our business activities. A decision by a governmental authority or other third party to deny, delay or restrictively condition the issuance of a new or renewed permit or other approval, or to revoke or substantially modify an existing permit or other approval, could have a material adverse effect on our ability to initiate or continue operations at the affected location or facility. Expansion of our existing operations is also predicated on securing the necessary environmental or land use permits and other approvals, which we may not receive in a timely manner or at all.

In order to obtain permits and renewals of permits and other approvals in the future, we may be required to prepare and present data to governmental authorities pertaining to the potential adverse impact that any proposed pipeline or processing-related activities may have on the environment, individually or in the aggregate, including on public and Indian lands. Certain approval procedures may require preparation of archaeological surveys, endangered species studies and other studies to assess the environmental impact of new sites or the expansion of existing sites. Compliance with these regulatory requirements is expensive and significantly lengthens the time needed to develop a site or pipeline alignment. Also, obtaining or renewing required permits or other approvals is sometimes delayed or prevented due to community opposition and other factors beyond our control. The denial of a permit or other permit essential to our operations or the imposition of restrictive conditions with which it is not practicable or feasible to comply could impair or prevent our ability to develop or expand a property or right-of-way. Significant opposition to a permit or other approval by neighboring property owners, members of the public or non-governmental organizations, or other third parties or delay in the environmental review and permitting process also could impair or delay our ability to develop or expand a property or right-of-way. New legal requirements, including those related to the protection of the environment, could be adopted at the federal, state and local levels that could materially adversely affect our operations (including our ability to gather, transport or process or the pace of gathering, transporting or processing natural gas), our cost structure or our customers ability to use our services. Such current or future regulations could have a material adverse effect on our business and we may not be able to obtain or renew permits or other approvals in the future.

A shortage of skilled labor in the midstream natural gas industry could reduce labor productivity and increase costs, which could have a material adverse effect on our business and results of operations.

The transportation, storage and processing of natural gas and the fractionation of NGLs requires skilled laborers in multiple disciplines such as equipment operators, mechanics and engineers, among others. If we experience shortages of skilled labor in the future, our labor and overall productivity or costs could be materially and adversely affected. If our labor prices increase or if we experience materially increased health and benefit costs for employees, our results of operations could be materially and adversely affected.

In connection with the acquisition of midstream assets from Kinder Morgan in November 2012, Tallgrass Development entered into a Transition Services Agreement with Kinder Morgan pursuant to which Kinder Morgan shares its employees to aid in the provision of certain services for up to nine months following the acquisition. Certain of those services are related to the assets to be contributed to us in connection with the initial public offering and, as a result, we will rely on the shared Kinder Morgan employees for certain services during the transition period. Although we are in the process of hiring additional employees, we may be unable to complete the required hiring and training of the necessary employees during the nine-month transition period, which could have a material adverse effect on our business and results of operations.

Difficult conditions in the global capital markets, the credit markets and the economy in general could negatively affect our business and results of operations.

Our business may be negatively impacted by adverse economic conditions or future disruptions in the global financial markets. Included among these potential negative impacts are reduced energy demand and lower prices for our services, increased difficulty in collecting amounts owed to us by our customers and a reduction in our credit ratings (either due to tighter rating standards or as a result of such potential negative impacts), which could reduce our access to credit markets, raise the cost of such access or require us to provide additional collateral to our counterparties. Our ability to access available capacity under our credit facility could be impaired if one or more of our lenders fails to honor its contractual obligation to lend to us. If financing is not available when needed, or is available only on unfavorable terms, we may be unable to implement our business plans or otherwise take advantage of business opportunities or respond to competitive pressures.

If we fail to develop or maintain an effective system of internal controls, we may not be able to report our financial results accurately or prevent fraud, which would likely have a negative impact on the market price of our common units.

We prepare our financial statements in accordance with GAAP, but our internal accounting controls may not currently meet all standards applicable to companies with publicly traded securities. Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and to operate successfully as a publicly traded partnership. Our efforts to develop and maintain our internal controls may not be successful, and we may be unable to maintain effective controls over our financial processes and reporting in the future or to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002, which we refer to as Section 404. For example, Section 404 will require us, among other things, to annually review and report on, and our independent registered public accounting firm to attest to, the effectiveness of our internal controls over financial reporting. We must comply with Section 404 (except for the requirement for an auditor s attestation report, as described below) beginning with our fiscal year ending December 31, 2014. Any failure to develop, implement or maintain effective internal controls or to improve our internal controls could harm our operating results or cause us to fail to meet our reporting obligations. Given the difficulties inherent in the design and operation of internal controls over financial reporting, we can provide no assurance as to our, or our independent registered public accounting firm s, conclusions about the effectiveness of our internal controls, and we may incur significant costs in our efforts to comply with Section 404. Ineffective internal controls will subject us to regulatory scrutiny and a loss of confidence in our reported financial information, which could have an adverse effect on our business and would likely have a negative effect on the trading price of our common units.

For as long as we are an emerging growth company, we will not be required to comply with certain disclosure requirements that apply to other public companies.

In April 2012, President Obama signed into law the Jumpstart Our Business Startups Act, or the JOBS Act. For as long as we remain an emerging growth company as defined in the JOBS Act, we may take advantage of certain exemptions from various reporting requirements that are applicable to other public companies that are not emerging growth companies, including not being required to provide an auditor s attestation report on management s assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act and reduced disclosure obligations regarding executive compensation in our periodic reports. We will remain an emerging growth company for up to five years, although we will lose that status sooner if we have more than $1.0 billion of revenues in a fiscal year, have more than $700 million in market value of our limited partner interests held by non-affiliates, or issue more than $1.0 billion of non-convertible debt over a three-year period.

To the extent that we rely on any of the exemptions available to emerging growth companies, you will receive less information about our executive compensation and internal control over financial reporting than issuers that are not emerging growth companies. If some investors find our common units to be less attractive as a result, there may be a less active trading market for our common units and our trading price may be more volatile.

Our election to take advantage of JOBS Act extended accounting transition period may make our financial statements more difficult to compare to other public companies.

Pursuant to the JOBS Act, as an emerging growth company, we must make an election to opt in or opt out of the extended transition period for any new or revised accounting standards that may be issued by the Public Company Accounting Oversight Board (PCAOB) or the SEC. We have elected to take advantage of such extended transition period which means that when a standard is issued or revised and it has different application dates for public or private companies, we can, for so long as we are an emerging growth company, adopt the standard for private companies. This may make comparison of our financial statements with any other public company that either is not an emerging growth company or has opted out of using the extended transition period difficult or impossible as a result of our use of different accounting standards.

The outcome of future rate cases will determine the amount of income taxes that we will be allowed to recover.

In May 2005, the FERC issued a statement of general policy permitting a pipeline to include in its cost-of-service computations an income tax allowance provided that an entity or individual has an actual or potential income tax liability on income from the pipeline s public utility assets. The extent to which owners of pipelines have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis in rate cases where the amounts of the allowances will be established. An adverse determination by the FERC with respect to this issue could have a material adverse effect on our revenues, earnings and cash flows.

Our business could be negatively impacted by security threats, including cyber security threats, and related disruptions.

We rely on our information technology infrastructure to process, transmit and store electronic information, including information we use to safely operate our assets. We may face cyber security and other security threats to our information technology infrastructure, which could include threats to our operational and safety systems that operate our pipelines, plants and assets. We could face unlawful attempts to gain access to our information technology infrastructure, including coordinated attacks from hackers, whether state-sponsored groups, hacktivists, or private individuals. The age, operating systems or condition of our current information technology infrastructure and software assets and our ability to maintain and upgrade such assets could affect our ability to resist cyber security threats. We could also face attempts to gain access to information related to our assets through attempts to obtain unauthorized access by targeting acts of deception against individuals with legitimate access to physical locations or information, otherwise known as social engineering.

Our information technology infrastructure is critical to the efficient operation of our business and essential to our ability to perform day-to-day operations. Breaches in our information technology infrastructure or physical facilities, or other disruptions, could result in damage to our assets, safety incidents, damage to the environment, potential liability or the loss of contracts, and have a material adverse effect on our operations, financial position, results of operations and prospects.

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Risks Inherent in an Investment in Us

Our general partner and its affiliates, including Tallgrass GP Holdings, which owns our general partner and the general partner of Tallgrass Development, have conflicts of interest with us and limited duties to us and our unitholders, and they may favor their own interests to the detriment of us and our other common unitholders.

Tallgrass GP Holdings owns our general partner and appoints all of the officers and directors of our general partner. Tallgrass GP Holdings also owns and controls the general partner of Tallgrass Development. All of our current officers and a majority of the current directors of our general partner are also officers and/or directors of Tallgrass GP Holdings. Certain of our directors are also officers or principals of Kelso or EMG, whose affiliated entities, along with certain members of our management, own and control Tallgrass GP Holdings. Although our general partner has a duty to manage us in a manner that is beneficial to us and our unitholders, the officers and directors of our general partner have a fiduciary duty to manage our general partner in a manner that is in the best interests of its owners, including management, Kelso and EMG. Conflicts of interest will arise between our general partner and its owners, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its owners over our interests and the interests of our unitholders. These conflicts include the following situations, among others:

Neither our partnership agreement nor any other agreement requires Tallgrass GP Holdings or its owners to pursue a business strategy that favors us, and the officers and directors of Tallgrass GP Holdings have a fiduciary duty to make these decisions in the best interests of Tallgrass GP Holdings and its owners, which may be contrary to our interests. Tallgrass GP Holdings may choose to shift the focus of its investment and growth to areas not served by our assets.

Tallgrass GP Holdings, its owners, and their respective affiliates are not limited in their ability to compete with us and, other than Tallgrass Development s obligation to offer us certain assets pursuant to the right of first offer under the Omnibus Agreement, may offer business opportunities or sell midstream assets to third parties without first offering us the right to bid for them.

Our general partner is allowed to take into account the interests of parties other than us, such as Tallgrass GP Holdings, its owners, and their respective affiliates in resolving conflicts of interest and exercising certain rights under our partnership agreement, which has the effect of limiting its duty to our unitholders.

All of the current officers and directors of our general partner are also officers and/or directors of Tallgrass GP Holdings and will owe fiduciary duties to Tallgrass GP Holdings. The officers of our general partner will also devote significant time to the business of Tallgrass Development.

Our partnership agreement replaces the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing its duties, limits our general partner s liabilities and restricts the remedies available to our unitholders for actions that, without such limitations, might constitute breaches of fiduciary duty.

Except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval.

Disputes may arise under our commercial agreements with Tallgrass Development and its affiliates.

Our general partner determines the amount and timing of asset purchases and sales, borrowings, issuance of additional partnership securities and the creation, reduction or increase of reserves, each of which can affect the amount of cash available for distribution to our unitholders.

Our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is classified as a maintenance capital expenditure, which reduces operating surplus, or an expansion or investment capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash that is distributed to our unitholders and the ability of the subordinated units to convert to common units.

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Our general partner determines which costs incurred by it are reimbursable by us.

Our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the subordination period.

Our partnership agreement permits us to classify up to $40 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions on our subordinated or general partner units or to our general partner in respect of the IDRs.

Our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf.

Our general partner may limit its liability regarding our contractual and other obligations.

Our general partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if they own more than 80% of the common units.

Our general partner controls the enforcement of the obligations that it and its affiliates owe to us, including Tallgrass Development s and its affiliates obligations under the Omnibus Agreement and their commercial agreements with us.

Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

Our general partner may transfer its IDRs without unitholder approval.

Our general partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our general partner s IDRs without the approval of the conflicts committee of the board of directors of our general partner or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

Affiliates of our general partner are not limited in their ability to compete with us and have limited obligations to offer us the opportunity to acquire additional assets or businesses, which could limit our ability to grow and could adversely affect our results of operations and cash available for distribution to our unitholders.

Affiliates of our general partner, including Kelso, EMG, Tallgrass GP Holdings and its subsidiaries, including Tallgrass Development, are not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, in the future, affiliates of our general partner and the entities owned or controlled by affiliates of our general partner, including Tallgrass Development, may acquire, construct or dispose of additional midstream or other assets and may be presented with new business opportunities, without any obligation to offer us the opportunity to purchase or construct such assets or to engage in such business opportunities, other than Tallgrass Development s obligation to offer us certain assets pursuant to the right of first offer under the Omnibus Agreement. While affiliates of our general partner may offer us the opportunity to buy these or other additional assets, these affiliates of our general partner, including Tallgrass Development, are not contractually obligated to do so, other than as described above, and we are unable to predict whether or when such opportunities may arise.

Pursuant to the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner, its executive officers and directors or any of its affiliates, including Tallgrass Development. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for

breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. This may create actual and potential conflicts of interest between us and affiliates of our general partner, including Tallgrass Development, and result in less than favorable treatment of us and our common unitholders.

Reimbursements due to our general partner and its affiliates for services provided to us or on our behalf will reduce cash available for distribution to our common unitholders. The amount and timing of such reimbursements will be determined by our general partner.

Prior to making any distribution on our common units, we will reimburse our general partner and Tallgrass Development s general partner and its affiliates for expenses they incur and payments they make on our behalf. Under our partnership agreement and the Omnibus Agreement, we will reimburse our general partner and Tallgrass Development s general partner and its affiliates for certain expenses incurred on our behalf, including administrative costs, such as compensation expense for those persons who provide services necessary to run our business, and insurance expenses. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. The reimbursement of expenses and payment of fees, if any, to our general partner and Tallgrass Development s general partner and its affiliates will reduce the amount of available cash to pay cash distributions to our common unitholders.

Our partnership agreement requires that we distribute our available cash, which could limit our ability to grow and make acquisitions.

Our partnership agreement requires us to distribute our available cash to our unitholders. Accordingly, we will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. As a result, to the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow.

In addition, because we intend to distribute our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement, and we do not anticipate there being limitations in our new credit facility, on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which in turn may impact the available cash that we have to distribute to our unitholders.

While our partnership agreement requires us to distribute our available cash, our partnership agreement, including provisions requiring us to make cash distributions contained therein, may be amended.

While our partnership agreement requires us to distribute our available cash, our partnership agreement, including provisions requiring us to make cash distributions therein, may be amended. Our partnership agreement generally may not be amended during the subordination period without the approval of our public common unitholders other than in certain circumstances where no unitholder approval is required. However, our partnership agreement can be amended with the consent of our general partner and the approval of a majority of the outstanding common units (including common units held by our general partner and its affiliates, including Tallgrass Development) after the subordination period has ended. Affiliates of our general partner own, directly or indirectly, approximately 40% of our outstanding common units and 100% of our outstanding subordinated units.

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The NYSE does not require a publicly traded partnership like us to comply with certain of its corporate governance requirements.

Our common units are listed on the NYSE. Unlike most corporations, we are not required by NYSE rules to have, and we do not intend to have, a majority of independent directors on our general partner s board of directors or a compensation committee or a nominating and corporate governance committee. Additionally, any future issuance of additional common units or other securities, including to affiliates, will not be subject to the NYSE s shareholder approval rules. Accordingly, unitholders will not have the same protections afforded to certain corporations that are subject to all of the NYSE corporate governance requirements.

If you are not an eligible taxable holder, you will not be entitled to allocations of income or loss or distributions or voting rights on your common units and your common units will be subject to redemption.

In order to avoid any material adverse effect on the maximum applicable rates that can be charged to customers by our subsidiaries on assets that are subject to rate regulation by the FERC or an analogous regulatory body, we have adopted certain requirements regarding those investors who may own our common units. Eligible holders are individuals or entities subject to United States federal income taxation on the income generated by us or entities not subject to United States federal income taxation on the income generated by us, so long as all of the entity s owners are subject to such taxation. If a holder of our common units (other than affiliates of our general partner) is not a person who fits the requirements to be an eligible taxable holder, such holder will not receive allocations of income or loss or distributions or voting rights on its units and will run the risk of having its units redeemed by us at the market price calculated in accordance with our partnership agreement as of the date of redemption. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our general partner.

Our partnership agreement replaces our general partner s fiduciary duties to holders of our common units with contractual standards governing its duties.

Our partnership agreement contains provisions that eliminate the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law and replace those duties with several different contractual standards. For example, our partnership agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner, free of any duties to us and our unitholders other than the implied contractual covenant of good faith and fair dealing (which provides that a court will enforce the reasonable expectations of the partners where the language in the partnership agreement does not provide for a clear course of action). This provision entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:

- how to allocate business opportunities among us and its affiliates;
- whether to exercise its limited call right;
- whether to seek approval of the resolution of a conflict of interest by the conflicts committee of the board of directors of our general partner;
- how to exercise its voting rights with respect to the units it owns;
- whether to elect to reset target distribution levels;
- whether to transfer the IDRs or any units it owns to a third party; and
- whether or not to consent to any merger, consolidation or conversion of the partnership or amendment to the partnership agreement.

In addition, our partnership agreement provides that any construction or interpretation of our partnership agreement and any action taken pursuant thereto or any determination, in each case, made by our general partner in good faith, shall be conclusive and binding on all unitholders.

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Our partnership agreement restricts the remedies available to holders of our common units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that restrict the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our partnership agreement provides that:

- whenever our general partner, the board of directors of our general partner or any committee thereof (including the conflicts committee) makes a determination or takes, or declines to take, any other action in their respective capacities, our general partner, the board of directors of our general partner and any committee thereof (including the conflicts committee), as applicable, is required to make such determination, or take or decline to take such other action, in good faith, meaning that it subjectively believed that the decision was in the best interests of our partnership, and, except as specifically provided by our partnership agreement, will not be subject to any other or different standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation, or at equity;

- our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as such decisions are made in good faith;

- our general partner and its officers and directors will not be liable for monetary damages to us or our limited partners resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers and directors, as the case may be, acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and

- our general partner will not be in breach of its obligations under the partnership agreement (including any duties to us or our unitholders) if a transaction with an affiliate or the resolution of a conflict of interest is:

    - approved by the conflicts committee of the board of directors of our general partner, although our general partner is not obligated to seek such approval;

    - approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates;

    - determined by the board of directors of our general partner to be on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or

    - determined by the board of directors of our general partner to be fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, any determination by our general partner or the conflicts committee must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the conflicts committee and the board of directors of our general partner determines that the resolution or course of action taken with respect to the affiliate transaction or conflict of interest satisfies either of the standards set forth in the third and fourth bullets above, then it will be presumed that, in making its decision, the board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership challenging such determination, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Holders of our common units have limited voting rights and are not entitled to select our general partner or elect members of its board of directors.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management s decisions regarding our business. Unitholders have no right on an annual or ongoing basis to select our general partner or elect its board of directors.

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Rather, the board of directors of our general partner, including the independent directors, is appointed by Tallgrass GP Holdings, as a result of it owning our general partner, and not by our unitholders. Furthermore, if the unitholders are dissatisfied with the performance of our general partner, they have little ability to remove our general partner. As a result of these limitations, the price at which the common units trade could be diminished because of the absence or reduction of a takeover premium in the trading price. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders ability to influence the manner or direction of management.

Even if holders of our common units are dissatisfied, they cannot currently remove our general partner without its consent.

Unitholders are currently unable to remove our general partner without its consent because our general partner and its affiliates own sufficient units to be able to prevent its removal. The vote of the holders of at least 66 2/3% of all outstanding common and subordinated units voting together as a single class is required to remove our general partner. Tallgrass Development owns an aggregate of approximately 64% of our outstanding common and subordinated units. This gives Tallgrass Development the ability to prevent the involuntary removal of our general partner. Also, if our general partner is removed without cause during the subordination period and units held by our general partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically convert into common units and any existing arrearages on our common units will be extinguished. A removal of our general partner under these circumstances would adversely affect our common units by prematurely eliminating their distribution and liquidation preference over our subordinated units, which would otherwise have continued until we had met certain distribution and performance tests. Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding our general partner liable for actual fraud or willful misconduct in its capacity as our general partner. Cause does not include most cases of charges of poor management of the business, so the removal of our general partner because of unitholder dissatisfaction with the performance of our general partner in managing our partnership will most likely result in the termination of the subordination period and conversion of all subordinated units to common units.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Unitholders voting rights are further restricted by a provision of our partnership agreement providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees, persons who acquired such units with the prior approval of the board of directors of our general partner and transferees of any of the foregoing, provided such transferee is an affiliate of the transferor, cannot vote on any matter.

Our general partner interest or the control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of Tallgrass GP Holdings to transfer all or a portion of its ownership interest in our general partner to a third party. The new owner of our general partner would then be in a position to replace the board of directors and officers of our general partner with its own designees and thereby exert significant control over the decisions made by the board of directors and officers. This effectively permits a change of control without the vote or consent of the unitholders.

The IDRs of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its IDRs to a third party at any time without the consent of our unitholders. If our general partner transfers its IDRs to a third party but retains its general partner interest, our general partner may not have the same incentive to grow our partnership and increase quarterly distributions to unitholders over

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time as it would if it had retained ownership of its IDRs. For example, a transfer of IDRs by our general partner could reduce the likelihood of Tallgrass Development selling or contributing additional midstream assets to us, as Tallgrass Development would have less of an economic incentive to grow our business, which in turn would impact our ability to grow our asset base.

We may issue additional units without unitholder approval, which could negatively impact unitholders existing ownership interests.

Our partnership agreement does not limit the number of additional limited partner interests that, including limited partner interests that rank senior to the common units, we may issue at any time without the approval of our unitholders. The issuance by us of additional common units or other equity securities of equal or senior rank could have the following effects:

- our existing unitholders proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- because the amount payable to holders of IDRs is based on a percentage of the total cash available for distribution, the distributions to holders of IDRs will increase even if the per unit distribution on common units remains the same;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Affiliates of our general partner may sell units in the public or private markets, and such sales could have an adverse impact on the trading price of the common units.

Affiliates of our general partner indirectly hold an aggregate of 9,700,000 common units and 16,200,000 subordinated units. All of the subordinated units will convert into common units at the end of the subordination period and may convert earlier under certain circumstances. In addition, we have agreed to provide our general partner and its affiliates with certain registration rights. The sale of these units in the public or private markets could have an adverse impact on the price of the common units or on any trading market that may develop.

Our general partner may limit its liability regarding our obligations.

Our general partner may limit its liability under contractual arrangements so that the counterparties to such arrangements have recourse only against our assets, and not against our general partner or its assets. Our general partner may therefore cause us to incur indebtedness or other obligations that are nonrecourse to our general partner. Our partnership agreement permits our general partner to limit its liability, even if we could have obtained more favorable terms without the limitation on liability. In addition, we are obligated to reimburse or indemnify our general partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise available for distribution to our unitholders.

Our general partner has a limited call right that may require unitholders to sell units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price that is not less than their then-current market price, as calculated pursuant to the terms of our partnership agreement. As a result, unitholders may be required to sell common units at an undesirable time or price and may not receive any return on investment. Unitholders may also incur a tax liability upon a sale of your units. Affiliates of our general partner indirectly own approximately 40% of our outstanding common units. At the end of the subordination period, assuming no additional issuances of common units (other than upon the conversion of the subordinated units), affiliates of our general partner will indirectly own approximately 64% of our outstanding common units.

Our general partner, or any transferee holding a majority of the IDRs, may elect to cause us to issue common units to it in connection with a resetting of the minimum quarterly distribution and the target distribution levels related to the IDRs, without the approval of the conflicts committee of our general partner or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

The holder or holders of a majority of the IDRs, which is currently our general partner, have the right, at any time when there are no subordinated units outstanding and the holders have received incentive distributions at the highest level to which they are entitled (48.0%) for each of the prior four consecutive fiscal quarters (and the amount of each such distribution did not exceed adjusted operating surplus for each such quarter), to reset the minimum quarterly distribution and the initial target distribution levels at higher levels based on our cash distribution at the time of the exercise of the reset election. Following a reset election, the minimum quarterly distribution will be reset to an amount equal to the average cash distribution per unit for the two fiscal quarters immediately preceding the reset election (such amount is referred to as the reset minimum quarterly distribution), and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution. Our general partner has the right to transfer the IDRs at any time, in whole or in part, and any transferee holding a majority of the IDRs shall have the same rights as our general partner with respect to resetting target distributions.

In the event of a reset of the minimum quarterly distribution and the target distribution levels, the holders of the IDRs will be entitled to receive, in the aggregate, the number of common units equal to that number of common units which would have entitled the holders to an average aggregate quarterly cash distribution in the prior two quarters equal to the average of the distributions on the IDRs in the prior two quarters. Our general partner will also be issued the number of general partner units necessary to maintain its general partner interest in us that existed immediately prior to the reset election. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not otherwise be sufficiently accretive to cash distributions per common unit. It is possible, however, that our general partner or a transferee could exercise this reset election at a time when it is experiencing, or expects to experience, declines in the cash distributions it receives related to its IDRs and may therefore desire to be issued common units rather than retain the right to receive incentive distribution payments based on target distribution levels that are less certain to be achieved in the then current business environment. This risk could be elevated if our IDRs have been transferred to a third party. As a result, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued common units to our general partner in connection with resetting the target distribution levels.

Your liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law, and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. You could be liable for any and all of our obligations as if you were a general partner if a court or government agency were to determine that:

- we were conducting business in a state but had not complied with that particular state s partnership statute; or

- your right to act with other unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute control of our business.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Transferees of common units are liable both for the obligations of the transferor to make contributions to the partnership that were known to the transferee at the time of transfer and for those obligations that were unknown if the liabilities could have been determined from the partnership agreement. Neither liabilities to partners on account of their partnership interest nor liabilities that are non-recourse to the partnership are counted for purposes of determining whether a distribution is permitted.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the IRS were to treat us as a corporation for federal income tax purposes, which would subject us to entity-level taxation, then our cash available for distribution to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service, or IRS, on this or any other tax matter affecting us.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. A change in our business or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35.0%, and would likely pay state and local income tax at varying rates. Distributions would generally be taxed again as corporate dividends (to the extent of our current and accumulated earnings and profits), and no income, gains, losses, deductions, or credits would flow through to you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to you would be substantially reduced. Therefore, if we were treated as a corporation for federal income tax purposes there would be material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

If we were subjected to a material amount of additional entity-level taxation by individual states, it would reduce our cash available for distribution to our unitholders.

Changes in current state law may subject us to additional entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of such additional tax on us by a state will reduce the cash available for distribution to you. Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to entity-level taxation, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

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The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations of applicable law, possibly on a retroactive basis.

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by legislative, judicial or administrative changes or interpretations of applicable law at any time. For example, from time to time, members of the U.S. Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. One such recent legislative proposal would have eliminated the qualifying income exception upon which we rely for our treatment as a partnership for federal income tax purposes. We are unable to predict whether any of these changes or any other proposals will be reintroduced or will ultimately be enacted or whether judicial or administrative interpretations of applicable law will change. Any such changes could negatively impact the value of an investment in our common units. Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes.

Our unitholders share of our income will be taxable to them for federal income tax purposes even if they do not receive any cash distributions from us.

Because a unitholder will be treated as a partner to whom we will allocate taxable income which could be different in amount than the cash we distribute, a unitholder s allocable share of our taxable income will be taxable to the unitholder, which may require the payment of federal income taxes and, in some cases, state and local income taxes on the unitholder s share of our taxable income even if it receives no cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the conclusions of our counsel expressed in this filing or from the positions we take, and the IRS s positions may ultimately be sustained. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel s conclusions or the positions we take. A court may not agree with some or all of our counsel s conclusions or the positions we take. Any contest with the IRS, and the outcome of any IRS contest, may have a materially adverse impact on the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

Tax gain or loss on the disposition of our common units could be more or less than expected.

If you sell your common units, you will recognize a gain or loss for federal income tax purposes equal to the difference between the amount realized and your tax basis in those common units. Because distributions in excess of your allocable share of our net taxable income decrease your tax basis in your common units, the amount, if any, of such prior excess distributions with respect to the common units you sell will, in effect, become taxable income to you if you sell such common units at a price greater than your tax basis in those common units, even if the price you receive is less than your original cost. Furthermore, a substantial portion of the amount realized on any sale or other disposition of your common units, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder s share of our nonrecourse liabilities, if you sell your common units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

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Tax-exempt entities and non-U.S. persons face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult a tax advisor before investing in our common units.

We will treat each purchaser of common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. Our counsel is unable to opine as to the validity of such filing positions. A successful IRS challenge also could affect the timing of these tax benefits or the amount of gain from your sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns.

We prorate our items of income, gain, loss and deduction for federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction for federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations, and although the U.S. Treasury Department issued proposed Treasury Regulations allowing a similar monthly simplifying convention, such regulations are not final and do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders. Our counsel has not rendered an opinion with respect to our monthly convention for allocating taxable income and losses.

A unitholder whose common units are loaned to a short seller to cover a short sale of common units may be considered as having disposed of those common units. If so, the unitholder would no longer be treated for federal income tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose common units are loaned to a short seller to cover a short sale of common units may be considered as having disposed of the loaned common units, the unitholder may no longer be treated for federal income tax purposes as a partner with respect to those common units during the period of the loan to the short seller and may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Our counsel has not rendered an opinion regarding the treatment of a unitholder where common units are loaned to a short seller to cover a short sale of common units; therefore, our unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller should consult a tax advisor to discuss whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from loaning their common units.

We will adopt certain valuation methodologies and monthly conventions for federal income tax purposes that may result in a shift of income, gain, loss and deduction between our general partner and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional units or engage in certain other transactions, we will determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and our general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of taxable income, gain, loss and deduction between our general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of taxable gain from our unitholders sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders tax returns without the benefit of additional deductions.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have technically terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Tallgrass Development owns approximately 64% of the total interests in our capital and profits. Therefore, a transfer by Tallgrass Development of all or a portion of its interests in us could result in a termination of our partnership for federal income tax purposes. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year if the termination occurs on a day other than December 31 and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in the unitholder s taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has recently announced a publicly traded partnership technical termination relief program whereby, if a publicly traded partnership that technically terminated requests publicly traded partnership technical termination relief and such relief is granted by the IRS, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

As a result of investing in our common units, you will likely become subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire properties.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently own property or conduct business in a number of states, most of which currently impose a personal income tax on individuals. Most of these states also impose an income tax on corporations and other entities. As we make acquisitions or expand our business, we may own property or conduct business in additional states that impose a personal income tax. It is your responsibility to file all federal, state and local tax returns. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in our common units.

Compliance with and changes in tax laws could adversely affect our performance.

We are subject to extensive tax laws and regulations, including federal and state income taxes and transactional taxes such as excise, sales/use, payroll, franchise and ad valorem taxes. New tax laws and regulations and changes in existing tax laws and regulations are continuously being enacted that could result in increased tax expenditures in the future. Many of these tax liabilities are subject to audits by the respective taxing authority. These audits may result in additional taxes as well as interest and penalties.

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

Unregistered Sales of Equity Securities

On February 6, 2013, in connection with our formation, we issued to (i) our general partner a 2% general partner interest in us in exchange for $20 and (ii) Tallgrass Development a 98% limited partner interest in us in exchange for $980. These transactions were exempt from registration under Section 4(2) of the Securities Act. There were no other unregistered sales of securities during the three months ended March 31, 2013.

Use of Proceeds

On May 13, 2013, our Registration Statement on Form S-1 (File No. 333-187595), as amended, filed with the SEC in connection with the Offering was declared effective. The Offering closed on May 17, 2013 and we sold 14,600,000 common units to the public, including a 1,550,000 common unit overallotment exercised by the underwriters. The price to the public was $21.50 per common unit and the aggregate gross proceeds totaled approximately $313.9 million. Expenses related to the Offering included approximately $18.0 million for the underwriters discount, and approximately $1.6 million for the structuring fee. Barclays Capital Inc., Citigroup Global Markets Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated and Deutsche Bank Securities Inc. acted as joint book-running managers of the Offering.

The net proceeds of approximately $295.9 million were used to repay approximately $295.9 million of the debt assumed from TD in connection with the Offering. The structuring fee and certain other expenses related to the Offering were paid from the proceeds of borrowings under our credit facility.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

Not applicable.

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Item 6. Exhibits

Exhibit No.	Description
3.1	Certificate of Limited Partnership of Tallgrass Energy Partners, LP (incorporated by reference to Exhibit 3.1 to the Partnership s Registration Statement on Form S-1 (File No. 333-187595), as amended, filed on March 28, 2013).
3.2	Certificate of Amendment to Certificate of Limited Partnership of Tallgrass Energy Partners, LP (incorporated by reference to Exhibit 3.2 to the Partnership s Registration Statement on Form S-1 (File No. 333-187595), as amended, filed on March 28, 2013).
3.3	Amended & Restated Agreement of Limited Partnership of Tallgrass Energy Partners, LP, dated May 17, 2013 (incorporated by reference to Exhibit 3.2 to the Partnership s Current Report on Form 8-K filed on May 17, 2013).
3.4	Certificate of Formation of Tallgrass MLP GP, LLC (incorporated by reference to Exhibit 3.4 to the Partnership s Registration Statement on Form S-1 (File No. 333-187595), as amended, filed on March 28, 2013).
3.5	Second Amended and Restated Limited Liability Company Agreement of Tallgrass MLP GP, LLC, dated May 17, 2013 (incorporated by reference to Exhibit 3.4 to the Partnership s Current Report on Form 8-K filed on May 17, 2013).
31.1*	Rule 13a-14(a)/15d-14(a) Certification of David G. Dehaemers, Jr.
31.2*	Rule 13a-14(a)/15d-14(a) Certification of Gary J. Brauchle.
32.1*	Section 1350 Certification of David G. Dehaemers, Jr.
32.2*	Section 1350 Certification of Gary J. Brauchle.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

* - filed herewith

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SIGNATURES

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.

Tallgrass Energy Partners, LP

(registrant)

By: Tallgrass MLP GP, LLC, its general partner

Date: June 26, 2013

By: /s/ Gary J. Brauchle

Name: Gary J. Brauchle

Title: *Executive Vice President, Chief Financial Officer and Treasurer*

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