Tallgrass Energy Partners, LP
Form 10-K
March 11, 2014
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

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

For the Fiscal Year Ended December 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)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	**Name of each exchange on which registered**
Common Units Representing Limited Partner Interests	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

None

Indicate by check mark whether the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨ No x

Indicate by check mark whether the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

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

The aggregate market value of voting and non-voting common equity held by non-affiliates on June 30, 2013, the last business day of the Registrant s most recently completed second fiscal quarter (based on the closing sale price of $20.87 of the Registrant s Common Units, as reported by the New York Stock Exchange on such date) was approximately $304.7 million.

On March 1, 2014, 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.

British Thermal Units or Btus: the amount of heat energy needed to raise the temperature of one pound of water by one degree Fahrenheit.

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

Delivery point: the point at which product in a pipeline is delivered to the end user.

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.

liquefied natural gas or 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.

MMBtu: One million British Thermal Units.

Mcf: One thousand cubic feet.

MMcf: One million cubic feet.

natural gas liquids or 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

As used in this Annual Report, unless the context otherwise requires; we, us, our, the Partnership, TEP and similar terms refer to Tallgrass Energy Partners, LP, together with its consolidated subsidiaries. The term our general partner refers to Tallgrass MLP GP, LLC. References to Tallgrass Development or TD refer to Tallgrass Development, LP. References to Kelso are to Kelso & Company and its affiliated investment funds and other entities under its control, and references to EMG are to The Energy & Minerals Group, its affiliated investment funds and other entities under its control.

A reference to a Note herein refers to the accompanying Notes to Consolidated Financial Statements contained in Item 8. Financial Statements and Supplementary Data. 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 Annual 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, strategy, expect, intend, pla believe, project, budget, potential, or continue, and similar expressions are used to identify forward-looking statements. Without limiting the generality of the foregoing, forward-looking statements contained in this Annual Report include our expectations of plans, strategies, objectives, growth and anticipated financial and operational performance, including guidance regarding our and TD 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 Annual 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;

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 Annual 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.

Item 1. Business

Tallgrass Energy Partners, LP (NYSE:TEP) is a growth-oriented publicly traded Delaware limited partnership formed in February 2013 by Tallgrass Development to own, operate, acquire and develop midstream energy assets in North America. We provide natural gas transportation and storage services for customers in the Rocky Mountain and Midwest regions of the United States through our Tallgrass Interstate Gas Transmission System, which we refer to as the TIGT System, and provide processing services for customers in Wyoming through our Casper and Douglas natural gas processing and West Frenchie Draw natural gas treating facilities, which we refer to as the Midstream Facilities. Our operations are located in the United States and are organized into two reporting segments:

Gas Transportation and Storage the ownership and operation of FERC-regulated interstate natural gas pipelines and integrated natural gas storage facilities that provide services primarily to on-system customers such as third-party local distribution companies, or 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, as well as water transportation services provided to producers.

For a detailed description of these assets, please see Our Assets below.

On May 17, 2013, we closed our initial public offering (IPO) of 14,600,000 common units at a price of $21.50 per unit. In connection with the IPO, TD contributed 100% of the membership interests in Tallgrass Interstate Gas Transmission, LLC (TIGT), which owns the TIGT System and Tallgrass Midstream, LLC (TMID), which owns the Midstream Facilities, to us in exchange for common and subordinated units representing limited partner interests in us and other consideration, as detailed in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Overview *Initial Public Offering*.

Our Assets

Our assets currently consist of the TIGT System and the Midstream Facilities, each of which is described in more detail below. We are strategically located in and provide services to certain key hydrocarbon basins, including the Denver-Julesburg Basin, the Powder River Basin, the Wind River Basin and the Anadarko Basin.

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Additional segment and financial information is contained in our segment results included in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and the notes to our consolidated financial statements included in Item 8. Financial Statements and Supplementary Data of this Annual Report.

TIGT System

The TIGT System is a FERC-regulated natural gas transportation and storage system with approximately 4,645 miles of varying diameter transportation pipelines serving Wyoming, Colorado, Kansas, Missouri and Nebraska. The natural gas currently transported on the TIGT System primarily comes from the Denver-Julesburg Basin and the Niobrara and Mississippi Lime shale formations. The TIGT System also includes the Huntsman natural gas storage facility, located in Cheyenne County, Nebraska. The TIGT System is a well-established and operationally flexible natural gas transportation and storage system that has been serving customers in the Midwest for approximately 75 years. The system s flexibility is derived from its multiple receipt and delivery interconnects, numerous pipeline segments and extensive footprint in the Midwest. The following tables provide operational information regarding our transportation and storage assets as of December 31, 2013 and for the years ended December 31, 2013 and 2012:

			Approximate Average Daily Throughput (MMcf/d) [1]		
	Approximate Number of Miles	Approximate Compression (Horsepower)	Year Ended December 31, 2013	Year Ended December 31, 2012	Year Ended December 31, 2011
Transportation	4,645	136,608	313	385	448

(1) As explained below, throughput is not a significant determinant of the revenues on the TIGT system.

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	Overall Gas Storage Capacity (Bcf)	Working Gas Storage Capacity (Bcf)	Maximum Withdrawal Rate (MMcf/d)
Storage	35.1	15.1	210

The TIGT System primarily provides transportation and storage services to on-system customers such as local distribution companies and industrial users, including ethanol plants, and irrigation and grain drying operations, which depend on the TIGT System s interconnections to their facilities to meet their demand for natural gas and a majority of whom pay FERC-approved recourse rates. For the years ended December 31, 2013 and 2012, approximately 75% and 65%, respectively, of our transportation revenue was generated from contracts with on-system customers.

Under transportation agreements and FERC tariff provisions, TIGT offers its customers firm and interruptible transportation and storage services, including no-notice service and park and loan services.

Firm Service. Firm transportation contracts obligate our customers to pay a fixed monthly reservation charge to reserve an agreed upon amount of pipeline capacity for transportation regardless of the actual pipeline capacity used by the customer during each month. In addition to monthly reservation charges, we also assess firm transportation customers usage charges based on actual volume of natural gas transported. Firm storage contracts obligate our customers to pay a fixed monthly charge for the firm right to inject, withdraw and store a specified volume of natural gas regardless of the amount of storage capacity actually utilized by the customer. Firm service storage customers are also assessed usage charges based on the actual quantities of natural gas injected into or withdrawn from storage. For the year ended December 31, 2013, approximately 93% of our transportation and storage revenues were generated under firm transportation and storage contracts.

Interruptible Service. Under interruptible service contracts, our customers pay fees based on their actual utilization of assets for transportation and storage services. These customers are not assured capacity or service on the TIGT System. If firm service physical capacity is not being fully utilized or if there is excess capacity that has not been contracted for firm service, the TIGT System can allocate such capacity to interruptible services. We also provide natural gas park and loan services to assist customers in managing short-term gas surpluses or deficits. Under our park and loan service agreements, customers are charged a usage fee based on the quantities of natural gas they store in (park), or borrow from (loan), our facilities. The TIGT System derived approximately 3% of its revenues for the year ended December 31, 2013 through interruptible services.

The table below sets forth certain information regarding our gas transportation and storage segment as of December 31, 2013:

	Capacity	Total Firm Contracted Capacity (1)	% of Capacity Subscribed under Firm Contracts	Weighted Average Remaining Firm Contract Life (2)
Transportation	1,089 MMcf/d	622 MMcf/d	57%	4 years
Storage	15.1 Bcf(3)	11 Bcf	73%	2 years

(1) Reflects total capacity reserved under firm contracts.

(2) Weighted by contracted capacity.

(3) Represents working gas storage capacity.

We have the authority to make gas purchases and sales, as needed for the TIGT System operations, pursuant to our currently effective FERC natural gas tariff. We do not take title to the natural gas transported or stored for our customers, which mitigates our direct commodity price risk. However, our tariff provides that we may retain a portion of our customers natural gas as compensation for natural gas used in rendering service to such customer, including natural gas consumed by us in our operations as well as natural gas lost or unaccounted for as a result of venting, inherent measurement inaccuracies or events of force majeure, among other reasons. The TIGT system derived approximately 4% of its revenue for the year ended December 31, 2013 through gas sales.

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Midstream Facilities

We own and operate natural gas processing plants in Casper and Douglas, Wyoming and a natural gas treating facility at West Frenchie Draw, Wyoming through our wholly-owned subsidiary, TMID. The Casper and Douglas plants currently have combined processing capacity of approximately 190 MMcf/d, following the substantial completion of expansions of both facilities in the second half of 2013. The natural gas processed and treated at these facilities primarily comes from the Wind River Basin and the Powder River Basin, both in central Wyoming. We provide processing services to some of the largest and most active producers in these areas. The Douglas and Casper plants are strategically located to straddle the TIGT System for inlet feed to provide residue gas delivery to the TIGT System and are currently the only natural gas processing plants that provide straddle processing of natural gas flowing into the TIGT System in Wyoming. Gathering systems owned by third parties deliver gas into our processing facilities. Natural gas processing involves the separation of natural gas into pipeline-quality natural gas and a mixed NGL stream. The Douglas processing plant produces an unfractionated raw NGL stream that is delivered into an NGL product pipeline at the plant outlet. Both Casper and Douglas locations have receiving facilities for trucked in NGL supplies as well as stabilizer facilities to separate natural gasoline from the mixed NGL stream. NGLs produced by the Casper and Douglas plants are either sold into local markets consisting primarily of retail propane dealers and oil refiners or sold to Phillips 66 Company via its Powder River NGL pipeline.

The Casper plant also has an NGL fractionator with a capacity of approximately 3,500 barrels per day. Fractionation is the process by which NGLs are further separated into individual, more valuable components including ethane, propane, butane, isobutane and natural gasoline. The Casper fractionator separates NGLs into propane, field grade butane, and natural gasoline.

The West Frenchie Draw natural gas treating facility is located 50 miles west of Casper, Wyoming. Natural gas is delivered to the West Frenchie Draw facility from two of the area s major natural gas producers and treated to extract or reduce impurities, such as carbon dioxide and sulfur, prior to its delivery to our Casper or Douglas processing plants.

In addition to our existing Processing and Treating activities, during the fourth quarter of 2013, we entered into a joint venture agreement to invest in the construction and operation of a fresh water transportation pipeline located in Weld County, Colorado. The pipeline will primarily transport water for use in the exploration, development and production of oil or natural gas. The pipeline began operations in the first quarter of 2014. While TEP owns 50% of the company that owns and operates the water pipeline, TEP has the right to recover its capital invested before any subsequent distributions are shared equally by TEP and its partner.

Currently, 100% of our existing processing capacity at our Midstream Facilities has been reserved. We typically receive a fee, acreage dedication or, in some cases, an agreement to pay for a minimum amount of throughput in exchange for reserved processing capacity for a given customer. The majority of our cash flow generated in this segment is fee-based due to the conversion of certain keep whole processing contracts to fee-based contracts during 2013.

The table below sets forth certain information regarding our processing segment as of December 31, 2013 and for the years ended December 31, 2013, 2012 and 2011:

Approximate	**Capacity Under**	**Weighted Average**	**Approximate Average Inlet Volumes (MMcf/d)**

Plant Capacity (MMcf/d) (1)	Contract	Remaining Contract Term (2)	Year Ended December 31, 2013	Year Ended December 31, 2012	Year Ended December 31, 2011
190	100%	4 years	133	123	117

(1) The West Frenchie Draw natural gas treating facility treats natural gas before it flows into the Casper and Douglas plants and therefore does not result in additional inlet capacity.
(2) Based on the average annual reservation capacity for each such contract s remaining life.

Processing Segment Customers

NGLs fractionated by the Casper plant are sold into local markets consisting primarily of retail propane dealers and oil refiners. NGLs processed by the Douglas plant are sold to Phillips 66 Company via its Powder River NGL pipeline. For the year ended December 31, 2013, Phillips 66 Company, as a purchaser of NGLs we produce and sell on behalf of our processing customers, accounted for approximately 62% of our total revenues. While we currently sell a significant amount of our NGLs produced by the Douglas plant to Phillips 66 Company, we believe there is a sufficient market for these NGLs that if Phillips 66 Company did not purchase them, they would be sold to other buyers who could transport them either on the Powder River NGL pipeline, by truck, by rail, or by other means.

Processing Contracts

Our processing services are typically provided pursuant to contracts featuring characteristics of one, or a combination of more than one, of the following contractual arrangements. In addition, many of our processing contracts obligate our customers to pay a fixed monthly reservation charge for the right to have a specified volume of gas processed regardless of the amount of processing capacity actually utilized by the customer.

Fee-based. A majority of our contracts at the Midstream Facilities are primarily based upon a fixed fee and/or a volumetric-based fee rate, which are typically tied to reserved capacity or inlet volumes.

Percent of Proceeds. Some of our contracts contain a percent of proceeds component, in which we process our customer s natural gas, sell the resulting NGLs and residue gas and divide the proceeds of those sales between us and the customer. Some of our percent of proceeds contracts also require our customers to pay a monthly reservation fee for capacity at our processing facilities.

Keep Whole. Keep whole provisions constitute the third type of contract at the Midstream Facilities. Under these arrangements, we are required to replace the Btu content of the NGLs extracted from inlet wet gas processed with purchased dry natural gas.

As of December 31, 2013, approximately 66% of our reserved capacity was subject to fee-based contracts, with the remaining 34% subject to percent of proceeds or keep whole contracts. The weighted average contract term for all contracts is approximately four years.

Tallgrass Development

TD owns 9,700,000 of our common units and 16,200,000 of our subordinated units, representing approximately 63% of our outstanding equity. In addition, TD is controlled by its general partner, Tallgrass Development GP, LLC, which is wholly-owned by Tallgrass GP Holdings, LLC, the sole owner of our general partner. Our general partner owns a 2% general partner interest in us and all of our incentive distribution rights, or IDRs. TD contributed the TIGT and TMID assets to us in connection with the IPO. However, TD continues to own and manage a substantial portfolio of midstream assets, including the following, which we refer to as the Retained Assets:

- a substantial organic growth project referred to in this Annual Report as the Pony Express Project, which upon completion will consist of an approximately 690-mile oil pipeline connecting the Bakken Shale to Cushing, Oklahoma. The Pony Express Project primarily consists of (i) the acquisition of the Pony Express Assets , which include approximately 430 miles of natural gas pipeline, rights of way and related equipment acquired, from TIGT by Tallgrass Pony Express, LLC (PXP), an indirect wholly-owned subsidiary of TD, (ii) the conversion of the Pony Express Assets into an oil pipeline serving the Bakken Shale and other nearby oil producing basins and (iii) the construction of an approximately 260-mile southward extension of the converted oil pipeline to provide deliveries to Cushing, Oklahoma. The converted pipeline and related expansion pipeline forming the Pony Express Project is expected to be placed in service in the second half of 2014.

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the Trailblazer Pipeline, an approximately 439-mile interstate pipeline with a capacity of up to 862 MMcf/d, that transports natural gas from southeastern Wyoming to interconnections with the Natural Gas Pipeline Company of America and Northern Natural Gas Company pipeline systems in Nebraska; and

a 50% interest in, and operation of, the Rockies Express Pipeline, or REX Pipeline, an approximately 1,698-mile modern natural gas pipeline with a long-haul design capacity of up to 1.8 Bcf/d, that extends from Opal, Wyoming and Meeker, Colorado to Clarington, Ohio.

Pursuant to an Omnibus Agreement, entered into upon the closing of the IPO, among us, our general partner, TD and its general partner (the Omnibus Agreement), TD granted us a right of first offer to acquire certain assets, including each of the Retained Assets described above, if TD decides to sell such assets. TD is otherwise under no obligation to offer to sell us additional assets or to pursue acquisitions jointly with us, and we are under no obligation to buy any assets from TD or pursue any such joint acquisitions. However, given the significant economic interest in us held by TD and its affiliates, we believe TD will be incentivized to offer us the opportunity to acquire the Retained Assets as each matures into an operating profile more conducive to our principal business objective of increasing the quarterly cash distributions that we pay to our unitholders over time while ensuring the ongoing stability of our business.

Competition

Our principal competitors in our natural gas transportation and storage market include companies that own major natural gas pipelines, such as Wyoming Interstate Company, LLC, Colorado Interstate Gas Company, LLC, Cheyenne Plains Gas Pipeline Company, LLC and Southern Star Central Gas Pipeline, Inc., many of whom also have existing storage facilities connected to their transportation systems that compete with our storage facilities. Pending and future construction projects, if and when brought on line, may also compete with our natural gas transportation, storage, processing and treating services and certain of our competitors may have capital and other resources greater than ours.

We also experience competition in the natural gas processing business. Our principal competitors for processing business include other facilities that service our supply areas, such as the other regional processing and treating facilities in the Greater Powder River Basin which include plants owned and operated by Kinder Morgan Energy Partners, LP, which we refer to as Kinder Morgan, ONEOK Partners, LP, Western Gas Partners, LP, Access Midstream Partners, LP, Crestwood Midstream Partners, LP and Meritage Midstream Services II, LLC. Casper and Douglas, however, are currently the only plants that provide straddle processing of natural gas flowing into the TIGT System in Wyoming. In addition, due to the growing nature of the liquids-rich plays in the Wind River Basin and Powder River Basin, it is possible that one of our competitors could build additional processing facilities that service our supply areas.

In addition, as a provider of midstream services to the natural gas industry, we generally compete with other forms of energy available to consumers, including electricity, coal, propane and fuel oils. Several factors influence the demand for natural gas, including price changes, the availability of natural gas and other forms of energy, the level of business activity, conservation, legislation and governmental regulations, and the ability to convert to alternative fuels and weather.

Regulatory Environment

Federal Energy Regulatory Commission

As an interstate transportation and storage system, the rates, terms of service and continued operations of the TIGT System are subject to regulation by the FERC, under among other statutes, the Natural Gas Act of 1938, or NGA, the

Natural Gas Policy Act of 1978, or the NGPA, and the Energy Policy Act of 2005, or EP Act 2005.

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The FERC has jurisdiction over, among other things, the construction, ownership and commercial operation of pipelines and related facilities used in the transportation and storage of natural gas in interstate commerce, including the modification, extension, enlargement and abandonment of such facilities. The FERC also has jurisdiction over the rates, charges and terms and conditions of service for the transportation and storage of natural gas in interstate commerce.

The rates and terms for access to pipeline transportation services are subject to extensive regulation. In recent years, the FERC has undertaken various initiatives to increase competition within the natural gas industry. As a result of these initiatives, interstate natural gas transportation and marketing entities have been substantially restructured to remove barriers and practices that historically limited non-pipeline natural gas sellers, including producers, from competing effectively with interstate pipelines for sales to local distribution companies and large industrial and commercial customers. The FERC s regulations require, among other things, that interstate pipelines 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 available pipeline capacity and other relevant information, and permit pipeline shippers under certain circumstances to release contracted transportation and storage capacity to other shippers, thereby creating secondary markets for such services. The result of the FERC s initiatives has been to eliminate the interstate pipelines historical role of providing bundled sales service of natural gas and to require pipelines to offer unbundled storage and transportation services on a nondiscriminatory basis. The rates for such transportation and storage services are subject to the FERC s ratemaking authority, and the FERC exercises its authority by applying cost-of-service principles to limit the maximum and minimum levels of tariff-based recourse rates; however it also allows for the negotiation of rates as a cost-based alternative rate and may grant market-based rates in certain circumstances, typically with respect to storage services. The 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.

2011 Section 5 Fuel Settlement

In November 2010, we received notice of a FERC proceeding related to the TIGT System pursuant to Section 5 of the NGA. The proceeding set for hearing a determination of whether our current rates, which were approved by the FERC in our last transportation rate case settlement, remain just and reasonable. The FERC made no findings in its order as to what would constitute just and reasonable rates or a reasonable return for TIGT. A proceeding under Section 5 of the NGA is prospective in nature and any potential change in the rates charged to customers on the TIGT System can only occur after the FERC has issued a final order.

In September 2011, the FERC approved a settlement among the parties, which resolves all issues in the proceeding and provides shippers on the TIGT System with prospective reductions in the fuel and gas and lost and unaccounted for gas rates, referred to as the Fuel Retention Factors, effective November 1, 2011. The settlement also provides shippers with credits equal to the reduced rates for the period from June 1, 2011 through October 31, 2011. The settlement resulted in a 27% reduction in the Fuel Retention Factors paid by shippers effective June 1, 2011, as compared to the Fuel Retention Factors approved and in effect on March 1, 2011. The settlement also provided for a second stepped reduction effective January 1, 2012, resulting in a total 30% reduction in the Fuel Retention Factors billed to shippers for certain segments of the former Pony Express pipeline system. Except for these reductions to the Fuel Retention Factors, other transportation and storage rates were not altered by the settlement. The settlement also established a moratorium of one year, from November 1, 2011 until November 1, 2012, during which neither we nor any of our customers participating in the settlement could initiate a rate proceeding under NGA Sections 4 or 5 to increase or reduce the recourse rates or fuel retainage percentages on the TIGT System. The settlement also required us to file with the FERC a cost and revenue study prior to November 1, 2015, although we have no obligation to file an NGA Section 4 rate proceeding.

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Pony Express Abandonment

On August 6, 2012, TIGT filed an application with the FERC to: (1) abandon the Pony Express Assets and the natural gas service therefrom by transferring the assets to an affiliate, PXP, 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, which we refer to as the Replacement Gas Facilities. By order issued September 12, 2013, TIGT was granted authorization to abandon the Pony Express Assets and construct the Replacement Gas Facilities.

Following an abandonment authorization granted by the FERC in September 2013, in December 2013, TIGT removed the Pony Express Assets from gas service and sold those assets to PXP, a wholly-owned subsidiary of TD, for approximately $83.0 million. In this Annual Report, we refer to (i) the abandonment of the Pony Express Assets, (ii) the construction of the Replacement Gas Facilities and incremental costs of continuing existing gas service at TIGT and related contractual reimbursements, (iii) the sale of the Pony Express Assets to PXP and (iv) ongoing reimbursements from PXP to TIGT for costs incurred to construct the Replacement Gas Facilities and to transport gas on third party pipelines to enable continuation of service to customers who previously received gas transported on the abandoned portion of the TIGT System, collectively as the Pony Express Abandonment. For additional information, see Note 9 *Commitments and Contingent Liabilities* to the Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data.

Market Behavior Rules; Posting and Reporting Requirements

The EPAct 2005, among other matters, amended the NGA to add an anti-manipulation provision that makes it unlawful for any entity to engage in prohibited behavior in contravention of rules and regulations to be prescribed by the FERC and, furthermore, provides the FERC with additional civil penalty authority. The FERC adopted rules implementing the anti-manipulation provision of the EPAct 2005 that make it unlawful for any entity, directly or indirectly in connection with the purchase or sale of natural gas transportation services subject to the jurisdiction of the FERC to (1) use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person.

These anti-manipulation rules apply to interstate gas pipelines and storage companies and intrastate gas pipelines and storage companies that provide interstate services as well as otherwise non-jurisdictional entities to the extent the activities are conducted in connection with gas sales, purchases or transportation subject to FERC jurisdiction. These anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but only to the extent such transactions do not have a nexus to jurisdictional transactions. The EPAct 2005 also amended the NGA and the NGPA to give the FERC authority to impose civil penalties for violations of these statutes, up to $1 million per day per violation. In connection with this enhanced civil penalty authority, the FERC issued a policy statement on enforcement to provide guidance regarding the enforcement of the statutes, orders, rules and regulations it administers, including factors to be considered in determining the appropriate enforcement action to be taken. Should we fail to comply with all applicable FERC-administered statutes, rule, regulations and orders, we could be subject to substantial penalties and fines.

The EPAct of 2005 also amended the NGA to authorize the FERC to facilitate price transparency in markets for the sale or transportation of physical natural gas in interstate commerce. The FERC has taken steps to enhance its market oversight and monitoring of the natural gas industry by adopting rules that (1) require buyers and sellers of annual quantities of 2,200,000 MMBtu or more of gas in any year to report by May on the aggregate volumes of natural gas they purchased or sold at wholesale in the prior calendar year; (2) report whether they provide prices to any index publishers and, if so, whether their reporting complies with the FERC s policy statement on price reporting; and (3) increase the Internet posting obligations of interstate pipelines.

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In addition, the Commodity Futures Trading Commission, or CFTC, is directed under the Commodities Exchange Act, or CEA, to prevent price manipulations for the commodity and futures markets, including the energy futures markets. Pursuant to the Dodd-Frank Wall Street Reform and Consumer Protection Act, or Dodd-Frank Act, in July 2010 and other authority, the CFTC has adopted anti-market manipulation regulations that prohibit fraud and price manipulation in the commodity and futures markets. The CFTC also has statutory authority to seek civil penalties of up to the greater of $1 million or triple the monetary gain to the violator for violations of the anti-market manipulation sections of the CEA.

Pipeline and Hazardous Materials Safety Administration

We are also subject to safety regulations imposed by PHMSA, including those regulations requiring us to develop and maintain integrity management programs to comprehensively evaluate certain areas along our pipelines and take additional measures to protect pipeline segments located in areas, which are referred to as high consequence areas, where a leak or rupture could potentially do the most harm.

The ultimate costs of compliance with the integrity management rules are difficult to predict. 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 high consequence areas, or HCAs, can have a significant impact on the costs to perform integrity testing and repairs. We conduct and will continue pipeline integrity testing programs to assess and maintain the integrity of our existing and future pipelines as required by the U.S. Department of Transportation regulations. 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 pipeline system.

In addition, we may be subject to enforcement actions and penalties for failure to comply with pipeline regulations. For example, on August 29, 2012, PHMSA notified TIGT 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. TIGT 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 and a Final Order was received on October 30, 2013 that required us to modify our operating procedures to further address Abnormal Operating Conditions.

The President signed into law in January 2012 The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, or The Pipeline Safety Act of 2011, which increased penalties for violations of safety laws and rules, among other matters, and may result in the imposition of more stringent regulations in the next few years. PHMSA is also currently considering changes to its regulations. PHMSA issued an Advisory Bulletin in May 2012, which advised pipeline operators of anticipated changes in annual reporting requirements and that if they are relying on design, construction, inspection, testing, or other data to determine the pressures at which their pipelines should operate, the records of that data must be traceable, verifiable and complete. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing (including hydrotesting) or modifying or replacing facilities to meet the demands of such pressures, could significantly increase our costs. In 2013, TIGT reported a total of 26.4 miles of pipeline for which it had incomplete records for MAOP. We are currently undertaking an extensive internal record review in view of the anticipated PHMSA annual reporting requirements. Additionally, failure to locate such records or verify maximum pressures could result in reductions of allowable operating pressures, which would reduce available capacity on our pipeline. There can be no assurance as to the amount or timing of future expenditures for pipeline integrity regulation, and actual future expenditures may be different from the amounts we currently anticipate. Regulations, changes to regulations or an increase in public expectations for pipeline safety may require additional reporting, the replacement of some of our pipeline segments, the addition of monitoring equipment and more frequent inspection or testing of our pipeline facilities. Any repair, remediation, preventative or mitigating actions may require significant capital and operating expenditures.

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Pipeline Integrity and Releases

From time to time, our pipeline may experience integrity issues. These integrity issues may cause explosions, fire, damage to the environment, damage to property and/or personal injury or death. In connection with these incidents, we may be sued for damages caused by an alleged failure to properly mark the locations of our pipelines and/or to properly maintain our pipelines. For example, failures occurred on two separate pipeline segments of the TIGT System during 2013; one in Kimball County, Nebraska on May 4, 2013 and one in Goshen County, Wyoming on June 13, 2013. The failures both resulted in the release 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 section in Kimball County, Nebraska were not material. The scope and cost of additional remediation activities related to the Goshen County failure are currently being evaluated. Depending upon the facts and circumstances of a particular incident, state and federal regulatory authorities may seek civil and/or criminal fines and penalties. For additional information, see Note 15 *Legal and Environmental Matters* to our Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data in this Form 10-K.

Environmental, Health and Safety Matters

The ownership, operation and expansion of our assets are subject to federal, state and local laws, regulations and potential liabilities arising under or relating to the protection or preservation of the environment, natural resources and human health. Moreover, we are subject to federal and state laws and regulations, the purpose of which is to maintain the safety of workers and the integrity of our pipeline, both generally and according to the standards applicable to the pipeline industry. The cost of complying with these laws and regulations can be significant, and we expect to incur significant compliance cost increase in the future as new, more stringent requirements are adopted and implemented. For example, regulation of greenhouse gas emissions under the Clean Air Act, or the CAA, and its implementing regulations could particularly result in significant cost additions. In addition, permitting requirements arising under these laws and regulations can negatively affect our ability to complete on a timely or cost-effective basis any future projects, for example, pipeline extensions, capacity expansion at processing facilities, and construction of storage facilities. We have an internal program of inspection designed to monitor and enforce compliance with pollution control and pipeline safety requirements. Such laws and regulations affect many aspects of our present and future operations, and generally require us to obtain and comply with various environmental registrations, licenses, permits, authorizations and other approvals, or submit to inspections or investigations. Liability under such laws and regulations may be incurred without regard to fault, including, for example, under the Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, Resource Conservation and Recovery Act, or RCRA, and analogous state laws for the remediation of contaminated areas. We are currently conducting remediation at several sites to address contamination. For 2014, we have budgeted approximately $576,000 for these ongoing environmental remediation projects. Private parties, including but not limited to the owners of properties through which our pipeline passes, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for noncompliance with such laws, regulations and permits issued thereunder or for personal injury or property damage. Our insurance may not cover all environmental risks and costs and/or may not provide sufficient coverage in the event that an environmental claim is made against us.

Failure to comply with these laws, regulations, permits, approvals or authorizations or to meet the requirements of new environmental laws, regulations or permits, approvals and authorizations, may also expose us to civil, criminal and administrative fines, penalties and/or temporary or permanent interruptions in our operations that could influence our business, financial position, results of operations and prospects. For example, if an accidental leak or release of natural gas or other hazardous substance occurs from our pipeline, we may experience significant operational disruptions and we may also have to pay a significant amount in costs to clean up the leak or release, pay for government penalties, address natural resource damages, provide compensation for human exposure or property damage, comply with issued injunctions, which could compel us to take steps such as installing costly pollution control equipment or limiting or ceasing some or all of our operations, or a combination of these and other measures. The costs and liabilities resulting from failure to comply with environmental laws and regulations could negatively affect our business, financial position, results of operations and prospects. In addition, emission controls required under the CAA and other similar federal, state and local laws could require significant capital expenditures at our facilities.

In addition, we have agreed to a number of conditions in our environmental permits, 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 in the future, and we are unable to predict the effect that any such measures would have on our business, financial position, results of operations or prospects.

We are also subject to the requirements of the Occupational Health and Safety Act, or OSHA, the Pipeline Safety Improvement Act and other comparable federal and state statutes. In general, we expect that we may have to increase expenditures in the future to comply with higher industry and regulatory safety standards. Such increases in expenditures could become significant over time.

For additional information regarding Environmental, Health and Safety Matters, please read Item 1A. Risk Factors.

Developments in GHG Regulations

Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of natural gas, are examples of GHGs. Various laws and regulations exist or are under development that seek to regulate the emission of such GHGs, including the EPA programs to regulate 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.

Because our operations, including our compressor stations, emit various types of GHGs, primarily methane and carbon dioxide, such new legislation or regulation could increase our costs related to operating and maintaining our facilities. Depending on the particular new law, regulation or program adopted, we could be required to incur capital expenditures for installing new emission controls on our facilities, acquire permits or other authorizations for emissions of GHGs from our 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, as is the case with similarly situated entities in the industry, they could be significant to us. While we may be able to include some or all of such increased costs in the rates charged by our pipeline, such recovery of costs in all cases is uncertain 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 an adverse effect on our business, financial position, results of operations and prospects.

EPA Regulation of Internal Combustion Engines

Internal combustion engines used in our operations are also subject to EPA regulation under the CAA. The EPA published new regulations on emissions of hazardous air pollutants from reciprocating internal combustion engines on August 20, 2010. On January 14, 2013, the EPA signed a final rule amending these regulations and it was published in the Federal Register on January 30, 2013. The EPA also revised the NSPS for stationary compression ignition and spark ignition internal combustion engines on June 28, 2011 and made minor amendments, included in the January 14, 2013 final rule. Compliance with these new regulations may require

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significant capital expenditures for physical modifications and may require operational changes as well. We are not able to estimate such increased costs, however, as is the case with similarly situated entities in the industry, they could be significant for us.

Regulation of Hydraulic Fracturing

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. The practice of hydraulic fracturing has been subject to public scrutiny in recent years and various efforts to regulate, or in some cases prohibit, hydraulic fracturing have been, and are still being, pursued at the local, state and federal levels of government. For example, several states, including states in which we operate, have imposed disclosure requirements on hydraulic fracturing. Restrictions on hydraulic fracturing could adversely affect our operations by reducing the volumes of natural gas that we transport and in other ways.

Recent EPA Rules Regarding Oil and Natural Gas Air Emissions

In addition, on April 17, 2012, the EPA approved final rules that establish new air emission controls for oil and natural gas production, pipelines and processing operations. These rules were published in the Federal Register on August 16, 2012 and became effective on October 15, 2012. They have since been modified by EPA and are currently subject to ongoing legal challenge. Compliance with such rules could result in additional costs, including increased capital expenditures and operating costs. While we are not able at this time to estimate such additional costs, as is the case with similarly situated entities in the industry, they could be significant for us. Compliance with such rules may also make it more difficult for our customers to operate, thereby reducing the volume of natural gas transported through our pipelines, which may adversely affect our business.

Hazardous Substances and Waste

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, nonhazardous and hazardous wastes and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of nonhazardous and hazardous waste and may impose strict joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. For instance, CERCLA and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release or threatened release of a hazardous substance into the environment. We may handle hazardous substances within the meaning of CERCLA, or analogous state laws, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released or threatened to be released into the environment.

We also generate wastes that are subject to RCRA and comparable state laws. RCRA regulates both nonhazardous and hazardous solid wastes, but it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. It is possible that wastes used in our operations that are currently treated as non-hazardous wastes could be designated as hazardous wastes in the future, subjecting us to more rigorous and costly management and disposal requirements. It is also possible that federal or state regulatory agencies will adopt stricter management or disposal standards for non-hazardous wastes, including natural gas wastes. Any such changes in the laws and regulations could have a material adverse effect on our maintenance capital expenditures and operating expenses or otherwise impose limits or restrictions on our operations or those of our customers.

We currently own or lease properties where hydrocarbons are being or have been handled for many years. Hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us or on or under the locations where these hydrocarbons and wastes have been transported for treatment or disposal. We could also have liability for releases or disposal on properties owned or leased by others. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners and operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial operations to prevent future contamination.

Water

The federal CWA, the Oil Pollution Act of 1990, or OPA, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants, including petroleum products, into state waters as well as waters of the United States and impose requirements affecting our ability to conduct construction activities in waters and wetlands. Certain state regulations and general permits issued under the federal National Pollutant Discharge Elimination System program prohibit the discharge of pollutants and chemicals. Unauthorized discharges can subject owners of regulated facilities to strict, joint, and potentially unlimited liability for containment and removal costs, natural resource damages and other consequences. Spill prevention, control and countermeasure requirements of federal laws and analogous state laws require us to maintain spill prevention control and countermeasure plans. These laws also require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a hydrocarbon tank spill, rupture or leak. Regulations promulgated pursuant to OPA further require certain facilities to maintain oil spill prevention and oil spill contingency plans. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of stormwater runoff and wastewater from certain types of facilities. These permits may require us to monitor and sample the stormwater runoff and wastewater from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for noncompliance with discharge permits or other requirements of the CWA and analogous state laws and regulations.

Endangered Species

The ESA restricts activities that may affect endangered or threatened species or their habitats. While some our operations may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in substantial compliance with the ESA. However, the designation of previously unlisted endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans or limit future development in the affected areas.

National Environmental Policy Act

The NEPA establishes a national environmental policy and goals for the protection, maintenance and enhancement of the environment and provides a process for implementing these goals within federal agencies. A major federal agency action having the potential to significantly impact the environment requires review under NEPA and, as a result, many activities requiring FERC approval must undergo a NEPA review. A NEPA review can create delays and increased costs that could materially adversely affect our operations.

Employee Safety

We are subject to the requirements of OSHA and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with

OSHA requirements, including general industry standards, recordkeeping requirements, and monitoring of occupational exposure to regulated substances.

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Seasonality

Weather generally impacts natural gas demand for power generation and heating purposes, which in turn influences the value of transportation and storage. Price volatility also affects gas prices, which in turn influences drilling and production. Peak demand for natural gas typically occurs during the winter months, caused by the heating load. Nevertheless, because a high percentage of our transportation and storage revenues are derived from firm capacity reservation fees under long-term contracts, our transportation and storage revenues are not generally seasonal in nature. We experience some seasonality in our processing segment, as volumes at our processing facilities are slightly higher in the summer months.

Title to Properties and Rights-of-Way

Our real property falls into two categories: (i) parcels that we own in fee and (ii) parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities, permitting the use of such land for our operations. Portions of the land on which our pipelines and facilities are located are owned by us in fee title, and we believe that we have satisfactory title to these lands. The remainder of the land on which our pipelines and facilities are located are held by us pursuant to surface leases between us, as lessee, and the fee owner of the lands, as lessors. We have leased or owned much of these lands for many years without any material challenge known to us relating to the title to the land upon which the assets are located, and we believe that we have satisfactory leasehold estates or fee ownership to such lands. We believe that we have satisfactory title to all of our material leases, easements, rights-of-way, permits and licenses, and we have no knowledge of any material challenge to our title to such assets or their underlying fee title.

Some of the leases, easements, rights-of-way, permits and licenses we acquired in the IPO require the consent of the grantor of such rights, which in certain instances is a governmental entity. TD or its affiliates may continue to hold record title to portions of certain assets until we make the appropriate filings in the jurisdictions in which such assets are located and obtain any consents and approvals that are not obtained prior to transfer. Such consents and approvals would include those required by federal and state agencies or political subdivisions. In some cases, TD may, where required consents or approvals have not been obtained, temporarily hold record title to property as nominee for our benefit and in other cases may, on the basis of expense and difficulty associated with the conveyance of title, cause its affiliates to retain title, as nominee for our benefit, until a future date. We anticipate that there will be no material change in the tax treatment of our common units resulting from TD holding the title to any part of such assets subject to future conveyance or as our nominee.

Insurance

We generally share insurance coverage with TD, for which we reimburse TD and its affiliates pursuant to the terms of the Omnibus Agreement. The TD insurance program includes general and excess liability insurance, auto liability insurance, workers compensation insurance and property insurance. We maintain, through our general partner, director and officer liability insurance under a separate policy from TD s general partner. All insurance coverage is in amounts which management believes are reasonable and appropriate.

Employees

We do not have any employees. We are managed and operated by the board of directors and executive officers of our general partner. All of our employees are employed by an affiliate of the general partner of TD and devote the portion of their time to our business and affairs that is reasonably required to manage and conduct our operations. Under the terms of the Omnibus Agreement, we reimburse TD for the provision of various general and administrative services for our benefit and for direct expenses incurred by TD on our behalf, including services performed and expenses incurred by our executive management personnel in connection with our business and affairs.

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Available Information

We make certain filings with the SEC, including our Annual Report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments and exhibits to those reports. We make such filings available free of charge through our website, www.tallgrassenergy.com, as soon as reasonably practicable after they are filed with the SEC. The filings are also available through the SEC s website, www.sec.gov, at the SEC s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549 or by calling 1-800-SEC-0330. Our press releases and recent presentations are also available on our website.

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 pay any distribution at all, and 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 quarterly distribution at the current distribution level, or at all, 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 quarterly distribution at the current distribution level, at the minimum quarterly distribution level, or at all. 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;

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- 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 TD, 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. With respect to our transportation and storage segment, 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, 2013, approximately 93% 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, 2013. As of December 31, 2013, the weighted average duration of our processing contracts was approximately 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 679 MMcf/d for the year ended December 31, 2013 and transportation services revenue decreased from $142.4 million to $98.6 million over the same period, primarily due to the loss of revenue from the non-renewal of transportation contracts.

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 laws or regulations on the contracting practices of our customers.

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 nature of the processing industry and the attractive drilling profile of geographic areas served by our Midstream Facilities. Furthermore, TD 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.

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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.

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 (if Tallgrass Development decides to sell such assets) pursuant to the right of first offer under the Omnibus Agreement, 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 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 could 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 some 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: percent of proceeds and keep whole arrangements. As of December 31, 2013, approximately 34% of the reserved capacity in our processing segment was contracted under percent of proceeds or keep whole arrangements. Under percent 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 the Btu content of NGLs extracted from the inlet wet gas processed with purchased 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 NGL prices, it is more profitable for us to process natural gas under keep whole arrangements. When natural gas prices are high relative to

NGL prices, it is less profitable for us and our customers to process natural gas both because of the higher value of natural gas and 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 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 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;
- 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.

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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.

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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.

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 or midstream facilities could have a material adverse effect on our business, financial condition, results of operations and prospects. For example, 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. 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 a tariff governing services we provide is successfully challenged, we could be required to reduce rates charged to customers, 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.

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 processed 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.

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.

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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, in 2013 we completed 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.

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 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;

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 and NGLs;

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, taxation and hydraulic fracturing; and

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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 long 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 33 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 and ability to make distributions to unitholders. 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. 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

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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 Note 15 *Legal and Environmental Matters* to the consolidated financial statements included in Part II Item 8. Financial Statements and Supplementary Data of this Annual Report. 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 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.

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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 (including hydrotesting) or modifying or replacing facilities to meet the demands of verifiable pressures, could significantly increase our costs. In 2013, TIGT reported a total of 26.4 miles of pipeline for which it had incomplete records for MAOP. We are currently undertaking an extensive internal record review in view of the anticipated PHMSA annual reporting requirements. 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 TIGT 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. TIGT 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 and a Final Order was received on October 30, 2013 that required us to make minor modifications to our operating procedures regarding Abnormal Operating Conditions.

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 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 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.

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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. 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 requires reporting of GHG emissions by regulated facilities to the EPA on an annual basis. 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 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.

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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;

- 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;

- 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;

Gold and Bald Eagle Protection Act, or GBEPA, prohibits anyone, without a permit issued by the Secretary of the Interior, from taking bald eagles, including their parts, nests, or eggs. The Act defines take as pursue, shoot, shoot at, poison, wound, kill, capture, trap, collect, molest or disturb.

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; and

National Historic Preservation Act, or NHPA, and analogous state laws, which is intended to preserve and protect historical and archeological sites.

Various governmental authorities, including but not limited to the EPA, the U.S. Department of the Interior, the U.S. Department of Homeland Security, and analogous Federal, 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 2014, we have budgeted approximately $576,000 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. In June 2013, the EPA extended the current National Enforcement Initiatives, including the initiative related to Energy Extraction Activities, for 2014 through 2016. 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. For example, in August 2011, the U.S. EPA and the WDEQ conducted an inspection of the Leak Detection and Repair (LDAR) Program at the Casper Plant in Wyoming. In September 2011, TMID received a letter from the U.S. EPA alleging violations of the

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Standards of Performance of Equipment Leaks for Onshore Natural Gas Processing Plant requirements under the CAA. In April 2013, TMID received a letter from the U.S. EPA concerning settlement of this matter. Settlement negotiations with the U.S. EPA are continuing, including resolution of more recently identified LDAR issues.

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 in 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, EPA has 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 24, 2013, the U.S. Department of Interior published a proposed rule in the Federal Register that includes disclosure requirements and other mandates for hydraulic fracturing on federal lands. On August 4, 2011 a citizens group petitioned the EPA to promulgate rules under the TSCA imposing requirements related to testing, identification, recordkeeping, and disclosure of chemical substances and mixtures in chemicals used in oil and gas exploration and production and hydraulic fracturing operations. The EPA partially granted the petition on November 23, 2011. In partially granting the petition, the EPA explained that it would propose rules using TSCA authorities to obtain data on chemical substances and mixtures regarding hydraulic fracturing. The EPA denied the petition insofar as it requested that the EPA invoke TSCA authorities to collect information on chemicals used in the exploration and production sector in addition to those used in hydraulic fracturing. Some states have already imposed disclosure requirements associated with hydraulic fracturing, including states in which we operate.

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 or, in municipal settings, time, place and manner restrictions, 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. Further, additional state legislation or regulation may impact our expansion plans by delaying implementation or requiring additional approvals or modifications to expansion plans.

In addition, on April 17, 2012, the EPA approved final rules that establish new air emission controls for oil and natural gas production, pipelines and processing operations. These rules were published in the Federal Register on August 16, 2012 and became effective on October 15, 2012. 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 rule requires 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. 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 and has since reconsidered certain aspects of the rule. The case is currently in abeyance and EPA may reconsider other 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 issued rules cannot be predicted. Additionally, on December 11, 2012, seven states submitted a notice of intent to sue the EPA to compel the agency to make a determination as to whether standards of performance limiting methane emissions from oil and gas sources are appropriate, and, if so, to promulgate performance standards for methane emissions from the oil and gas sector, which was not addressed in the EPA rule that became effective on October 15, 2012. The notice of intent also requested the EPA issue emission guidelines for the control of methane emissions from existing oil and gas sources. Depending on whether rules are promulgated and the applicability and restrictions in any promulgated rule, compliance with such rules could result in additional costs, including increased capital expenditures and operating costs. While we are not able at this time to estimate such additional costs, as is the case with similarly situated entities in the industry, they could be significant for us. Compliance with such rules may also make it more difficult for our customers to operate, thereby reducing the volume of natural gas transported through our pipelines, which may adversely affect our business. Compliance with such rules could also generally 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.

Potential Increased Costs As a Result of EPA Regulation of Internal Combustion Engines Could Be Significant

Internal combustion engines used in our operations are also subject to EPA regulation under the CAA. The EPA published new regulations on emissions of hazardous air pollutants from reciprocating internal combustion engines on August 20, 2010. On January 14, 2013, the EPA signed a final rule amending these regulations and it was published in the Federal Register on January 30, 2013. The EPA also revised the NSPS for stationary compression ignition and spark ignition internal combustion engines on June 28, 2011 and made minor amendments, included in the January 14, 2013 final rule. Compliance with these new regulations may require significant capital expenditures for physical modifications and may require operational changes as well. We are not able to estimate such increased costs, however, as is the case with similarly situated entities in the industry, they could be significant for us.

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. Our pipeline tariff does not contain a fuel usage true-up mechanism. As such, 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

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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.

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

Our 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 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 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 credit facility, including a failure to meet the required financial ratios and tests, could result in a default or an event of default that could enable our lenders to restrict or prohibit our ability to make quarterly distributions and 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.

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.

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 and increased difficulty in collecting amounts owed to us by our customers 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.

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.

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 approval 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 store, transport or process natural gas or the pace of storing, 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.

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 intend to continue taking 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 the 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.

If we are unable to protect our information and telecommunication systems against disruptions or failures, our operations could be disrupted.

We rely extensively on computer systems to process transactions, maintain information and manage our business. Disruptions in the availability of our computer systems could impact our ability to service our customers and adversely affect our sales and results of operations. We are dependent on internal and third party information technology networks and systems, including the Internet and wireless communications, to process, transmit and store electronic information. Our computer systems are subject to damage or interruption due to system replacements, implementations and conversions, power outages, computer or telecommunication failures, computer viruses, security breaches, catastrophic events such as fires, tornadoes and hurricanes and usage errors by our employees. If our computer systems are damaged or cease to function properly, we may have to make a significant investment to fix or replace them, and we may have interruptions in our ability to service our customers. Although we attempt to eliminate or reduce these risks by using redundant systems, this disruption caused by the unavailability of our computer systems could nevertheless significantly disrupt our operations or may result in financial damage or loss due to, among other things, lost or misappropriated information.

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 owner, Tallgrass GP Holdings. 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,

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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 (if Tallgrass Development decides to sell such 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 a majority of the current 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 are also officers of the general partner of Tallgrass Development and will 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.

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.

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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 direct and indirect 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 (if Tallgrass Development decides to sell such 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

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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 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. Tallgrass Development currently owns approximately 40% of our outstanding common units and 100% of our outstanding subordinated units for a total limited partnership interest of approximately 64%.

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

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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.

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

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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. 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 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.

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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, including Tallgrass Development, 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.

Tallgrass Development currently holds 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. For additional information, see Note 10 *Partnership Equity and Distributions* to our Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data in this Form 10-K.

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. Tallgrass Development, an affiliate of our general partner, currently owns 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), Tallgrass Development will 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%) 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

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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%, 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

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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.

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 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 the positions we take. A court may not agree with some or all of 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

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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.

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. 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.

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 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 63% 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.

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 1B. Unresolved Staff Comments

None.

Item 2. Properties

A description of our properties is contained in Item 1. Business, *Our Assets* of this Annual Report.

Our principal executive offices are located at 6640 West 143rd Street, Suite 200, Overland Park, KS 66223 and our telephone number is 913-928-6060.

We own two office buildings in Lakewood, Colorado, with a portion of both being leased to a third party pursuant to a lease with an initial term through March 31, 2015. In addition, TD leases its offices in Overland Park, Kansas. We pay a proportionate share of the costs to occupy the building to TD pursuant to the Omnibus Agreement.

Item 3. Legal Proceedings

See Note 15 *Legal and Environmental Matters* to the consolidated financial statements included in Part II Item 8. Financial Statements and Supplementary Data of this Annual Report, which is incorporated by reference into this Part I Item 3 of this Annual Report.

Item 4. Mine Safety Disclosures

Not applicable.

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PART II

Item 5. Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market Information

Our common units have been listed on the New York Stock Exchange (NYSE) under the symbol TEP since the completion of our IPO on May 17, 2013. The following table sets forth the high and low sales prices of the common units during each subsequent quarter, as reported by the NYSE, as well as the amount of cash distributions per unit declared for the period May 17, 2013 through December 31, 2013.

Quarter Ended	High	Low	Distribution per Common Unit
December 31, 2013	$ 27.74	$ 23.00	$ 0.3150
September 30, 2013	24.00	21.12	0.2975
June 30, 2013	22.91	20.53	0.1422 (1)
March 31, 2013	N/A	N/A	N/A

(1) The distribution declared in the second quarter of 2013 was prorated for the period from May 17, 2013 to June 30, 2013.

Holders

As of March 1, 2014, there were 2 unitholders of record of our common units. This number does not include unitholders whose units are held in trust by other entities. The actual number of beneficial unitholders is greater than the number of holders of record. In addition, as of March 1, 2014, TD owned all 16,200,000 of our subordinated units and our general partner owned all 826,531 of our general partner units.

Equity Compensation Plan

See Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters for information regarding our Equity Compensation Plan.

Distributions of Available Cash

General. Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute our available cash to unitholders of record on the applicable record date, as determined by our general partner.

Definition of Available Cash. The term available cash generally means, for any quarter, all cash and cash equivalents on hand at the end of that quarter

less, the amount of cash reserves established by our general partner to:

- provide for proper conduct of business;
- comply with applicable law or regulation, any of our debt instruments or other agreements; or
- provide funds for distribution to unitholders and to our general partner for any one or more of the next four quarters;

plus, if our general partner so determines, all or any portion of the cash on hand on the date of distribution of available cash for the quarter, including cash on hand resulting from working capital borrowings made subsequent to the end of such quarter.

Minimum Quarterly Distribution. We intend to make cash distributions to the holders of common units on a quarterly basis in an amount equal to at least the minimum quarterly distribution, or MQD, of $0.2875 per unit or

$1.15 per unit on an annualized basis, to the extent we have sufficient cash from our operations after establishment of cash reserves and payment of fees and expenses, including payments to our general partner and its affiliates. However, there is no guarantee that we will pay the MQD on the units in any quarter. Even if our cash distribution policy is not modified or revoked, the amount of distributions paid under our policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement. Our general partner has broad discretion to establish cash reserves that it determines are necessary or appropriate to properly conduct our business. These can include cash reserves for future capital and maintenance expenditures, reserves to stabilize distributions of cash to our unitholders, reserves to reduce debt or, as necessary, reserves to comply with the terms of any of our agreements or obligations. We will be prohibited from making any distributions to unitholders if it would cause an event of default or if an event of default exists under our credit agreement.

General Partner Interest. Our general partner is currently entitled to 2% of all quarterly distributions that we make prior to our liquidation. As of March 1, 2014 our general partner interest is represented by 826,531 general partner units. Our general partner has the right, but not the obligation, to contribute a proportional amount of capital to us to maintain its current general partner interest. The general partner s 2% interest in these distributions will be reduced if we issue additional units in the future and our general partner does not contribute a proportional amount of capital to us to maintain its 2% general partner interest.

Incentive Distribution Rights. As quarterly distributions exceed the MQD and other higher target distribution levels, our general partner, as the holder of the IDRs, becomes entitled to increasing percentages (13%, 23% and 48%) of the distributions after the MQD and such higher target distribution levels have been achieved. For additional information, see Note 10 *Partnership Equity and Distributions* to our Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data in this Form 10-K.

Performance Graph

The following performance graph compares the performance of our common units with the NYSE Composite Index Total Return and the Alerian Total Return MLP Index during the period beginning on May 14, 2013, and ending on December 31, 2013. The graph assumes a $100 investment in our common units and in each of the indices at the beginning of the period and a reinvestment of distributions/dividends paid on such investments throughout the period.

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Recent Sales of Unregistered Equity Securities

None.

Repurchase of Equity by Tallgrass Energy Partners, LP or Affiliated Purchasers

None.

Item 6. Selected Financial Data

The historical financial statements included in this Annual 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 the consummation of our initial public offering of common units representing limited partner interests (the IPO) on May 17, 2013, Tallgrass Development, LP (Tallgrass Development or TD) contributed to us its equity interests in our Predecessor. 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 (TEP Pre-Predecessor Parent) prior to November 13, 2012 at which date TEP Pre-Predecessor Parent sold those assets, among others, to TD. The Predecessor Entities are referred to as TEP Predecessor for the period in which they were owned by TD, from November 13, 2012 through the completion of the IPO on May 17, 2013, and as TEP Pre-Predecessor for periods in which they were owned by TEP Pre-Predecessor Parent, prior to November 13, 2012. In certain circumstances and for ease of reading we discuss the financial results of our Predecessor as being our financial results during historic periods.

The following table shows selected historical financial and operating data of TEP and TEP Pre-Predecessor for the periods and as of the dates indicated. The selected historical financial data for the year ended December 31, 2011 and for the period from January 1 through November 12, 2012 is derived from the audited books and records of TEP Pre-Predecessor. The selected historical financial data for the period from November 13, 2012 to December 31, 2012 and the year ended December 31, 2013 are derived from the audited financial statements of TEP.

We derived the information in the following table from, and that information should be read together with and is qualified in its entirety by reference to, the consolidated financial statements and the accompanying notes included elsewhere in this Annual Report.

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Our operating results incorporate a number of significant estimates and uncertainties. Such matters could cause the data included herein to not be indicative of our future financial conditions or results of operations. A discussion of our critical accounting estimates is included in Management s Discussion and Analysis of Financial Condition and Results of Operations in Item 7.

	TEP		TEP Pre-Predecessor	
	Year Ended December 31, 2013	Period from November 13 to December 31, 2012	Period from January 1 to November 12, 2012	Year Ended December 31, 2011
	(in thousands, except per unit amounts)		(in thousands, except per unit amounts)	
Statement of operations data:				
Revenue	$ 267,708	$ 35,288	$ 220,292	$ 307,043
Operating income	$ 40,710	$ 1,311	$ 50,113	$ 75,499
Net income (loss)	$ 14,179	$ (1,408)	$ 51,496	$ 77,507
Net income allocable to limited partners	$ 6,991[(1)]	N/A	N/A	N/A
Net income per limited partner unit basic	$ 0.17[(1)]	N/A	N/A	N/A
Net income per limited partner unit diluted	$ 0.17[(1)]	N/A	N/A	N/A
Balance sheet data (at end of period):				
Property, plant and equipment, net	$ 594,911	$ 669,476	$ 717,486	$ 719,009
Total assets	$ 967,798	$ 1,035,814	$ 767,681	$ 772,896
Long-term debt	$ 135,000	$	$	$
Long-term debt allocated from TD	$	$ 390,491	$	$
Other:				
Distributions declared per common unit	$ 0.7547	N/A	N/A	N/A

(1) The net income allocated to the limited partners was based upon the number of days between the closing of the IPO on May 17, 2013 to December 31, 2013.

Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations

Overview

We are a growth-oriented publicly traded Delaware limited partnership that owns, operates, acquires and develops midstream energy assets in North America. We provide natural gas transportation and storage services for customers in the Rocky Mountain and Midwest regions of the United States through the TIGT System and provide processing services for customers in Wyoming through our Casper and Douglas natural gas processing and West Frenchie Draw natural gas treating facilities, which we refer to as the Midstream Facilities.

We intend to leverage our relationship with TD and utilize the significant experience of our management team to execute our growth strategy of acquiring midstream assets from TD 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 FERC-regulated 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, as well as water transportation services provided to producers.

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Summary of Results for the Year Ended December 31, 2013

Net income for the year ended December 31, 2013 was $14.2 million, with Adjusted EBITDA and Distributable Cash Flow (each as defined below under *Non-GAAP Measures*) of $74.6 million and $62.3 million, respectively. On May 17, 2013 we successfully completed our IPO, issuing 14.6 million common units to the public and raising gross proceeds of $313.9 million.

Factors and Trends Impacting Our Business

We expect to continue to be affected by certain key factors and trends described below. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about, or interpretations of, available information prove to be incorrect, our actual results may vary materially from our expected results. See also Item 1A. Risk Factors.

U.S. Natural Gas Supply and Demand Dynamics

Natural gas continues to be a critical component of energy supply and demand in the United States. We believe that the prospects for natural gas production increases are favorable and will be driven in part by increased demand resulting from population and economic growth, higher industrial consumption of natural gas in the U.S. as a result of its attractive cost and availability, potential for future exports of natural gas, as well as the continued displacement of coal-fired electricity generation by natural gas-fired electricity generation due to the low prices of natural gas and stricter government environmental regulations on the mining and burning of coal.

Growth in Production from Shale Plays

We believe that production growth in the Wind River Basin and Powder River Basin will benefit our Midstream Facilities and, to a lesser extent, the TIGT System with increased throughput volumes.

Growth Associated with Acquisitions and Expansion Projects

Growth associated with acquisitions

We believe that we are well-positioned to grow through accretive acquisitions. We intend to pursue acquisition opportunities from third parties as they become available, as well as acquisitions from TD s portfolio of midstream assets, which include the Pony Express Project, the Trailblazer Pipeline and TD s 50% interest in, and operation of, the REX Pipeline. Pursuant to the Omnibus Agreement, TD granted us the right of first offer to acquire each of the remaining Retained Assets if TD decides to sell those assets. TD is otherwise under no obligation to offer to sell us additional assets or to pursue acquisitions jointly with us, and we are under no obligation to buy any assets from TD or pursue any such joint acquisitions. However, given the significant economic interest in us held by TD and its affiliates, we believe TD will be incentivized to offer us the opportunity to acquire the Retained Assets as each matures into an operating profile more conducive to our principal business objective of increasing the quarterly cash distributions that we pay to our unitholders over time while ensuring the ongoing stability of our business.

In January 2014, TD offered the Trailblazer Pipeline to us for purchase. A special committee of the Board of Directors of our general partner, consisting solely of independent directors, has been formed and is evaluating the offer with assistance from external advisors engaged by the committee. The transaction has not been executed at this time and is subject to final negotiations and approval by the special committee and by the Board of Directors of our general partner. Although it is uncertain when or if TD will offer us the opportunity to acquire the other Retained Assets, we believe TD will offer us the opportunity to purchase part or all of the Pony Express Project at some point after the crude oil pipeline is placed in service (currently expected to be in the third quarter of 2014). We currently have no expectations regarding when or if TD would offer to sell all or any portion of its 50% interest in the REX Pipeline to us.

Growth associated with expansion projects

As production and demand for our services increase in the areas that our operations are located, we believe that we are well positioned to increase volumes to our systems through cost-effective capacity expansions. For example, in 2013, we completed an expansion of our Casper and Douglas plants and increased processing capacity from approximately 138.5 MMcf/d to approximately 190 MMcf/d and fractionation capabilities from approximately 2,000 barrels per day to approximately 3,500 barrels per day.

Transportation and Storage Customers

Currently, the customers on the TIGT System primarily consist of on-system customers such as LDCs and industrial users such as ethanol plants and irrigation and grain drying operations. These customers value the TIGT System s proximity to their facilities and the TIGT System s extensive footprint in the Midwest. LDCs and industrial users typically require a secure and reliable supply of natural gas over a sustained period of time to meet the needs of their customers and, as a result, these types of customers are incentivized to enter into long-term firm transportation and storage contracts to ensure both a ready supply of natural gas and sufficient transportation capacity over the life of the contract based on their maximum peak usage rather than their average usage requirements.

Historically, some of the customers on the TIGT System used the TIGT System to access other interstate pipelines for ultimate delivery to consuming markets outside of our areas of operations. Some of those customers entered into short-term transportation and storage agreements with TIGT and over the last several years, some of these customers have opted not to renew those contracts. We believe that reduced renewals may be attributable to competition from long-haul interstate pipelines and reduced drilling activity for dry gas in the Rocky Mountain region. As a result, we have seen a decline in the overall volumes transported on the TIGT System over the past several years. However, a significant portion of our current customer base is comprised of on-system customers, with approximately 75% of our transportation revenue during the year ended December 31, 2013 generated under contracts with on-system customers with a weighted average contract life of 3.5 years based on revenue. Given the high percentage of our transportation revenue that is derived from on-system customers, our long-term relationship with them and the tendency of these customers to renew their contracts in the past, we believe that our transportation services revenues have largely stabilized.

Interest Rates

The credit markets recently have experienced near-record lows in interest rates. As the overall economy strengthens, it is likely that monetary policy will tighten, resulting in higher interest rates to counter possible inflation. If this occurs, interest rates on floating rate credit facilities and future offerings in the debt capital markets could be higher than current levels, causing our financing costs to increase accordingly. In addition, there is a financing cost for the storage capacity user to carry the cost of the inventory while it is stored in the facility. That financing cost is impacted by the cost of capital or interest rate incurred by the storage user as well as the commodity cost of the natural gas in inventory. The higher the financing cost, the lower the margin that will remain from the price spread that was intended to be captured. Accordingly, a significant increase in interest rates could impact the demand for storage capacity independent of other market fundamentals. For additional information, please read Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Rising Operating Costs and Inflation

The current high level of natural gas exploration, development and production activities across the United States has resulted in increased competition for personnel and equipment. This may ultimately increase the prices we pay for labor, supplies, property and equipment. An increase in the general level of prices in the economy could have a similar effect. We may be unable to recover all of these increased costs from our customers. To the extent we are unable to procure necessary supplies or recover higher costs, our operating results will be negatively impacted.

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Recent Events

In January 2014, TD offered the Trailblazer Pipeline to us for purchase. A special committee of the Board of Directors of our general partner, consisting solely of independent directors, has been formed and is evaluating the offer with assistance from external advisors engaged by the committee. The transaction has not been executed at this time and is subject to final negotiations and approval by the special committee and by the Board of Directors of our general partner.

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 costs. Our operating expenses 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 consolidated 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.

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, net cash provided by operating activities 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 Financial Measures

We define Adjusted EBITDA as net income before interest, income taxes, depreciation and amortization, non-cash income or loss related to derivative instruments, non-cash long-term compensation expense,

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impairment losses, gains or losses on asset disposals and gains or losses on the repurchase, redemption or early retirement of debt. We did not quantify distributable cash flow on a historical basis, however subsequent to the closing of the IPO we began to use distributable cash flow, which we define as Adjusted EBITDA less cash interest cost 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 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 net income and net cash provided by operating activities and a reconciliation of distributable cash flow to net cash provided by operating activities, the most directly comparable GAAP financial measures, for each of the periods indicated:

	TEP		TEP Pre-Predecessor	
	Year Ended December 31, 2013	Period from November 13 to December 31, 2012	Period from January 1 to November 12, 2012	Year Ended December 31, 2011
	(in thousands)		(in thousands)	
Reconciliation of Adjusted EBITDA to Net Income (Loss)				
Net income (loss)	$ 14,179	$ (1,408)	$ 51,496	$ 77,507
Add:				
Interest expense (income), net	11,141	3,201	(1,661)	(2,101)
Depreciation and amortization expense	29,549	4,086	20,647	22,726
Loss on extinguishment of debt	17,526			
Non-cash loss (gain) related to derivative instruments	386	(273)		
Texas Margin Tax			279	296
Non-cash compensation expense	1,798			
Adjusted EBITDA	**$ 74,579**	**$ 5,606**	**$ 70,761**	**$ 98,428**
Reconciliation of Adjusted EBITDA and Distributable Cash Flow to Net Cash Provided by Operating Activities				
Net cash provided by operating activities	$ 83,666	$ 10,705	$ 81,335	$ 90,505
Add:				
Interest expense (income), net	11,141	3,201	(1,661)	(2,101)
Texas Margin Tax			279	296
	(20,228)	(8,300)	(9,192)	9,728

Other, including changes in operating working capital				
Adjusted EBITDA	**$ 74,579**	**$ 5,606**	**$ 70,761**	**$ 98,428**
Less:				
Maintenance capital expenditures	(8,773)			
Cash interest cost	(3,555)			
Distributable Cash Flow	**$ 62,251**			

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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		TEP Pre-Predecessor	
	Year Ended December 31, 2013	Period from November 13 to December 31, 2012	Period from January 1 to November 12, 2012	Year Ended December 31, 2011
	(in thousands)		(in thousands)	
Reconciliation of Adjusted EBITDA to Operating Income in the Gas Transportation and Storage Segment [(1)]				
Operating income (loss)	$ 27,595	$ (610)	$ 34,563	$ 52,910
Add:				
Depreciation and amortization expense	22,829	3,263	17,895	19,751
Non-cash loss (gain) related to derivative instruments	386	(273)		
Other income	2,157	482	1	203
Segment Adjusted EBITDA	**$ 52,967**	**$ 2,862**	**$ 52,459**	**$ 72,864**
Reconciliation of Adjusted EBITDA to Operating Income in the Processing Segment [(1)]				
Operating income	$ 16,472	$ 1,921	$ 15,550	$ 22,589
Add:				
Depreciation and amortization expense	6,720	823	2,752	2,975
Segment Adjusted EBITDA	**$ 23,192**	**$ 2,744**	**$ 18,302**	**$ 25,564**

(1) Segment results as presented represent total operating income and Adjusted EBITDA, including intersegment activity, for the Gas Transportation and Storage and Processing segments. Corporate and Other segment activity is excluded. For reconciliations to the consolidated financial data, see Note 16 *Reporting Segments* to the accompanying consolidated financial statements.

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Results of Operations

The following provides a summary of our results of operations for TEP and TEP Pre-Predecessor for the periods indicated:

	TEP		TEP Pre-Predecessor	
	Year Ended December 31, 2013	Period from November 13 to December 31, 2012	Period from January 1 to November 12, 2012	Year Ended December 31, 2011
	(in thousands, except operating data)		(in thousands, except operating data)	
Statements of Operations Data				
Revenues:				
Natural gas liquids sales	$ 146,313	$ 18,554	$ 106,355	$ 151,627
Natural gas sales	7,969	1,910	15,634	28,339
Transportation services	98,625	13,102	93,214	123,018
Processing and other revenues	14,801	1,722	5,089	4,059
Total revenues	267,708	35,288	220,292	307,043
Operating costs and expenses:				
Cost of sales and transportation services	137,285	18,298	101,452	150,120
Operations and maintenance	31,945	3,353	29,901	33,294
Depreciation and amortization	29,549	4,086	20,647	22,726
General and administrative	21,894	7,133	11,318	16,044
Taxes, other than income taxes	6,325	1,107	6,861	9,360
Total operating costs and expenses	226,998	33,977	170,179	231,544
Operating income	40,710	1,311	50,113	75,499
Interest (expense) income, net	(2,113)	235	1,661	2,101
Interest expense allocated from TD	(9,028)	(3,436)		
Loss on extinguishment of debt	(17,526)			
Other income, net	2,136	482	1	203
Income (Loss) before income taxes	14,179	(1,408)	51,775	77,803
Texas Margin Taxes			279	296
Net Income (Loss) to Member	$ 14,179	$ (1,408)	$ 51,496	$ 77,507
Other Financial Data [1]				
Adjusted EBITDA	$ 74,579	$ 5,606	$ 70,761	$ 98,428
Operating Data				
Operating Data (Mmcf/d):				
Transportation firm contracted capacity	679	702	762	795
Natural gas processing inlet volumes	133	127	122	117

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

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	TEP		TEP Pre-Predecessor	
	Year Ended December 31, 2013	Period from November 13 to December 31, 2012	Period from January 1 to November 12, 2012	Year Ended December 31, 2011
	(in thousands)		(in thousands)	
Segment Financial Data Gas Transportation and Storage [1]				
Revenues:				
Natural gas sales	$ 4,488	$ 208	$ 9,814	25,475
Transportation services	100,545	13,198	93,910	123,619
Processing and other revenues	26	6	278	42
Total revenues	105,059	13,412	104,002	149,136
Operating costs and expenses:				
Cost of sales and transportation services	10,424	1,560	14,378	30,560
Operations and maintenance	23,223	2,472	21,625	23,498
Depreciation and amortization	22,829	3,263	17,895	19,751
General and administrative	14,975	5,662	8,994	13,785
Taxes, other than income taxes	6,013	1,065	6,547	8,632
Total operating costs and expenses	77,464	14,022	69,439	96,226
Operating income (loss)	$ 27,595	$ (610)	$ 34,563	$ 52,910
Segment Adjusted EBITDA	$ 52,967	$ 2,862	$ 52,459	$ 72,864
Segment Financial Data Processing [1]				
Revenues:				
Natural gas liquids sales	$ 146,313	$ 18,554	$ 106,355	$ 151,627
Natural gas sales	3,481	1,702	5,820	2,864
Processing and other revenues	14,775	1,716	4,811	4,017
Total revenues	164,569	21,972	116,986	158,508
Operating costs and expenses:				
Cost of sales and transportation services	128,781	16,834	87,770	120,161
Operations and maintenance	8,722	881	8,276	9,796
Depreciation and amortization	6,720	823	2,752	2,975
General and administrative	3,562	1,471	2,324	2,259
Taxes, other than income taxes	312	42	314	728
Total operating costs and expenses	148,097	20,051	101,436	135,919
Operating income	$ 16,472	$ 1,921	$ 15,550	$ 22,589
Segment Adjusted EBITDA	$ 23,192	$ 2,744	$ 18,302	25,564

(1) Segment results as presented represent total revenue and Adjusted EBITDA, including intersegment activity, for the Gas Transportation and Storage and Processing segments. Corporate and Other segment activity is excluded. For reconciliations to the consolidated financial data, see Note 16 *Reporting Segments* to the accompanying consolidated financial statements.

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Year Ended December 31, 2013 Compared to the Period from January 1, 2012 to November 12, 2012

Revenues. Total revenues were $267.7 million for the year ended December 31, 2013, compared to $220.3 million for the period from January 1, 2012 to November 12, 2012, which represents a 6% increase in average monthly revenues. Average monthly revenues in the Gas Transportation and Storage segment decreased 12% while average monthly revenues in the Processing segment increased by 22%.

In the Gas Transportation and Storage segment, the decrease in average monthly revenues was primarily driven by a 60% decrease in average monthly natural gas sales revenue and a 7% decrease in average monthly transportation services revenue during 2013. The decrease in average monthly natural gas sales revenue was primarily caused by lower sales volumes as well as a 29% decrease in natural gas sales prices. Natural gas sales volumes decreased due to reduced natural gas recoveries from our customers caused by lower throughput as well as decreased sales of gas inventory at December 31, 2013. The decrease in average monthly transportation services revenue was primarily due to a decrease in transportation firm contracted capacity and from lower throughput volumes, primarily from off-system customers.

Higher revenues in the Processing segment were primarily attributable to (i) increased average monthly NGL sales due to an increase in average monthly volumes of NGLs processed during the year ended December 31, 2013 compared to the 2012 period as a result of new contracts, and (ii) an increase in average monthly processing fees of 167% resulting from new and revised fee-based contracts that were not in effect during the 2012 period. Increases were partially offset by a decrease in natural gas sales due to sales of residue gas purchased from a customer during the 2012 period that did not occur during the 2013 period and natural gas purchase and sales transactions in 2012 to redirect processed dry gas around the Casper plant in order to optimize plant capacity and efficiency.

Operating costs and expenses. Operating costs and expenses were $227.0 million for the year ended December 31, 2013 compared to $170.2 million for the period from January 1, 2012 to November 12, 2012, which represents a 16% increase in average monthly operating costs and expenses.

Cost of sales and transportation services were $137.3 million for the year ended December 31, 2013 compared to $101.5 million for the period from January 1, 2012 to November 12, 2012, which represents an 18% increase in average monthly cost of sales and transportation services. The increase was primarily attributable to processing costs associated with increased volumes in the Processing segment that were added during 2013 and resulted from new or revised fee-based contracts, partially offset by the purchase of residue gas from a customer in 2012 and gas purchases related to the natural gas purchase and sales transactions in 2012 (both discussed above). The increase in cost of sales and transportation services in the Processing segment was partially offset by decreased costs in the Gas Transportation and Storage segment associated with decreased gas sales and decreased fuel recoveries as a result of less throughput.

Operations and maintenance costs were $31.9 million for the year ended December 31, 2013 compared to $29.9 million for the period from January 1, 2012 to November 12, 2012. Although total operations and maintenance costs increased in the 2013 period, there was an actual 7% decrease in average monthly operations and maintenance costs. The decrease is primarily driven by lower expenses in the Gas Transportation and Storage segment related to decreased operating costs associated with a section of pipe that was idled in the second quarter of 2013, resulting in the sole shipper under contract for that section not transporting gas in the second half of 2013, and a reduction in integrity maintenance projects during 2013 when compared to the period from January 1, 2012 to November 12, 2012.

Depreciation and amortization was $29.5 million for the year ended December 31, 2013 compared to $20.6 million for the period from January 1, 2012 to November 12, 2012, which represents a 24% increase in average monthly depreciation and amortization. Average monthly depreciation and amortization was higher in both segments for the year ended December 31, 2013 compared to the period from January 1, 2012 to November 12, 2012 due to the higher cost basis of property, plant and equipment as a result of the acquisition of TIGT and TMID by TD on November 13, 2012.

General and administrative expenses during the year ended December 31, 2013 were $21.9 million compared to $11.3 million for the period from January 1, 2012 to November 12, 2012, which represents a 68% increase in average monthly general and administrative expenses. The increase was largely reflective of TEP Pre-Predecessor Parent s scale advantage during the 2012 period in supporting similar required administrative functions by a substantially larger number of operated businesses, as well as the additional costs we incurred associated with being a public company beginning in the second quarter of 2013.

Taxes, other than income taxes, were $6.3 million for the year ended December 31, 2013 compared to $6.9 million for the period from January 1, 2012 to November 12, 2012 which represents a 20% decrease in average monthly taxes, other than income taxes. The decrease was primarily due to lower property taxes in the Gas Transportation and Storage segment as a result of successful appeals with state taxing authorities on the assessed value of property during 2013.

Interest (expense) income. Interest expense of $2.1 million for the year ended December 31, 2013 was composed of interest and fees of $4.2 million primarily associated with TEP s revolving credit facility that were partially offset by $2.1 million primarily related to interest income and capitalized interest. Interest income of $1.7 million for the period from January 1, 2012 to November 12, 2012 primarily represents imputed interest on payments received from certain customers for reimbursement of the capital costs we incurred to connect these customers to our system. The level of interest income is decreasing over time as the balances due to us are being repaid.

Interest expense allocated from TD. Interest expense allocated from TD of $9.0 million for the year ended December 31, 2013 represents the interest expense related to the $400 million term loan allocated from TD, which was legally assumed by TEP and repaid upon closing of the IPO on May 17, 2013.

Loss on extinguishment of debt. The loss on extinguishment of debt of $17.5 million during the year ended December 31, 2013 represents the loss associated with the write off of deferred financing costs and unamortized discounts associated with the repayment of debt allocated from TD as discussed above.

Other income and expense. Other income for the year ended December 31, 2013 was $2.1 million compared to a negligible amount for the period from January 1, 2012 to November 12, 2012. Other income for the year ended December 31, 2013 primarily relates to rental income and a gain related to the favorable elimination of a liability associated with a small inactive storage field.

*Texas Margin Tax. D*uring 2012, 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 the acquisition of TIGT and TMID 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.

Year Ended December 31, 2013 Compared to the Period from November 13, 2012 to December 31, 2012

Revenues. Total revenues were $267.7 million for the year ended December 31, 2013, compared to $35.3 million for the period from November 13, 2012 to December 31, 2012, which represents consistent average monthly revenues for the periods.

The average monthly revenue in the Gas Transportation and Storage segment for the year ended December 31, 2013 increased by 3% compared to the average monthly revenue for the period from November 13, 2012 to December 31, 2012. The increase was primarily driven by higher average monthly revenue from natural gas sales in 2013 as compared to the period from November 13, 2012 to December 31, 2012 due to the timing of natural gas sales.

The Processing segment average monthly revenues for the year ended December 31, 2013 decreased 2% compared to the average monthly revenues for the period from November 13, 2012 to December 31, 2012. The decrease in revenues was primarily attributable to lower natural gas sales revenue due to sales of residue gas purchased from a customer during the 2012 period which did not occur in 2013, partially offset by increased average monthly NGL sales due to an increase in average monthly volumes of NGLs processed during the year ended December 31, 2013 as a result of new contracts.

Operating costs and expenses. Operating costs and expenses were $227.0 million for the year ended December 31, 2013 compared to $34.0 million for the period from November 13, 2012 to December 31, 2012, which represents a 12% decrease in average monthly operating costs and expenses.

Cost of sales and transportation services were $137.3 million for the year ended December 31, 2013 compared to $18.3 million for the period from November 13, 2012 to December 31, 2012, which represents a 1% decrease in average monthly cost of sales and transportation services.

Operations and maintenance costs were $31.9 million for the year ended December 31, 2013 compared to $3.4 million for the period from November 13, 2012 to December 31, 2012, which represents a 25% increase in average monthly operations and maintenance costs. The increase was primarily due to increased integrity maintenance projects in the Gas Transportation and Storage segment, as the majority of planned integrity maintenance projects for 2012 were completed prior to the sale of TIGT to TD in November 2012.

Depreciation and amortization was $29.5 million for the year ended December 31, 2013 compared to $4.1 million for the period from November 13, 2012 to December 31, 2012, which represents a 5% decrease in average monthly depreciation and amortization.

General and administrative expenses during the year ended December 31, 2013 were $21.9 million compared to $7.1 million for the period from November 13, 2012 to December 31, 2012, which represents a 60% decrease in average monthly general and administrative expenses. The decrease was primarily due to significant legal and other acquisition costs recognized during the 2012 period associated with the acquisition of TIGT and TMID on November 13, 2012.

Taxes, other than income taxes, were $6.3 million for the year ended December 31, 2013 compared to $1.1 million for the period from November 13, 2012 to December 31, 2012, which represents a 25% decrease in average monthly taxes, other than income taxes. The decrease was primarily due to lower property taxes in the Gas Transportation and Storage segment as a result of successful appeals with state taxing authorities on the assessed value of property during 2013.

Interest (expense) income. Interest expense of $2.1 million for the year ended December 31, 2013 was primarily composed of interest and fees of $4.2 million primarily associated with TEP s revolving credit facility that were partially offset by $2.1 million primarily related to interest income and capitalized interest.

Interest expense allocated from TD. Interest expense allocated from TD of $9.0 million for the year ended December 31, 2013 and $3.4 million for the period from November 13, 2012 to December 31, 2012 represents the interest expense related to the $400 million term loan allocated to TEP from TD, which was assumed and repaid by TEP upon closing of the IPO on May 17, 2013.

Loss on extinguishment of debt. The loss on extinguishment of debt of $17.5 million during the year ended December 31, 2013 represents the loss associated with the write off of deferred financing costs and unamortized discounts associated with the repayment of debt allocated to TEP from TD as discussed above.

Other income and expense. Other income for the year ended December 31, 2013 was $2.1 million compared to $0.5 million for the period from November 13, 2012 to December 31, 2012. Other income for the year ended December 31, 2013 primarily relates to rental income and a gain related to the favorable elimination of a liability associated with a small inactive storage field. Other income for the period from November 13, 2012 to December 31, 2012 primarily relates to rental income.

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Period from January 1 to November 12, 2012 Compared to the Year Ended December 31, 2011

Revenues. Total revenues were $220.3 million for the period from January 1 to November 12, 2012, compared to $307.0 million for the year ended December 31, 2011, which represents a 17% decrease in average monthly revenues. The decrease in average monthly revenues in the Gas Transportation and Storage segment and the Processing segment was 19% and 15%, respectively.

In the Gas Transportation and Storage segment, natural gas sales of $9.8 million in the period from January 1 to November 12, 2012 represent a 56% decrease in average monthly revenues compared to the year ended December 31, 2011. This decrease was attributable to a decrease in sales volumes attributable to the reduction in Fuel Retention Factors as a result of the Section 5 settlement that became effective on June 1, 2011 and a one-time sale of 2.0 Bcf of natural gas from storage in the third quarter of 2011 of approximately $8.1 million, partially offset by an increase in natural gas sales prices attributable to higher overall market prices. Excluding this one-time sale, natural gas revenues in the Gas Transportation and Storage segment would have been $17.3 million for the year ended December 31, 2011. In addition, a 12% decline in average monthly transportation services revenue during the 2012 period was attributable to lower throughput volumes. As described in Factors and Trends Impacting Our Business Transportation and Storage Customers above, we believe that our transportation revenues have largely stabilized.

Lower revenues in the Processing segment were primarily attributable to a decrease in average monthly NGL sales in the 2012 period due to lower ethane revenue attributable to significantly lower market prices for this product in 2012 and a reduction in average monthly sales of other NGLs due to lower market prices. This was partially offset by higher monthly average natural gas sales and an increase in processing and other revenues due to an increase in average monthly processing fees associated with increased volumes in the 2012 period. Although market prices for NGLs decreased during the period, our processing volumes increased due to the continuing trend of our customers focusing on drilling for gas with higher NGL content.

Operating costs and expenses. Operating costs and expenses were $170.2 million for the period from January 1 to November 12, 2012 compared to $231.5 million for the year ended December 31, 2011, which represents a 15% decrease in average monthly operating costs and expenses. These decreases are attributable to lower cost of sales and transportation services in both segments and lower general and administrative expenses in the Gas Transportation and Storage segment.

The 46% decrease in average monthly cost of sales and transportation services in the Gas Transportation and Storage segment was attributable to lower sales of natural gas volumes due to the reduction in Fuel Retention Factors as a result of the Section 5 Settlement. In addition, the 25% reduction in average monthly general and administrative expenses in this segment was the result of one-time bonuses paid to all employees of TEP Pre-Predecessor Parent in 2011 for attainment of a previously specified financial performance metric.

The Processing segment reported a 14% decrease in average monthly cost of sales and transportation services in the 2012 period. This decrease is attributable to lower market prices for purchased NGLs and natural gas.

Interest income, net. Interest income represents imputed interest on payments received from certain customers for reimbursement of the capital costs we incurred to connect these customers to our system. The level of interest income is decreasing over time as the balances due to us are being repaid.

Texas Margin Taxes. Our 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 being acquired 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.

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Period from November 13 to December 31, 2012 Compared to the Year Ended December 31, 2011

Revenues. Total revenues for the period from November 13 to December 31, 2012 were $35.3 million, which was comprised of $13.4 million in the Gas Transportation and Storage segment and $21.9 million in the Processing segment.

The average monthly revenue in the Gas Transportation and Storage segment decreased by 33% compared to the average monthly revenue for the year ended December 31, 2011. In addition to the decrease in average monthly natural gas sales attributable to the one-time 2.0 Bcf natural gas sale in the third quarter of 2011 and the reduction in Fuel Retention Factors, each as described above, average monthly natural gas sales volumes decreased in the period from November 13 to December 31, 2012 due to seasonality. During this time of year, many of our customers are withdrawing natural gas from storage to meet increased levels of demand in the winter months. We typically sell lower volumes of our own gas during these periods in order to maintain the volumes of gas that are required for the operational needs of the storage facility. The lower average monthly revenue for the November 13 to December 31, 2012 period was attributable to a reduction in natural gas sales and in transportation services revenue.

In the Processing segment, average monthly revenue for the period November 13 to December 31, 2012 increased by 4% compared to the average monthly revenue in the year ended December 31, 2011. This increase was attributable to higher natural gas sales and processing fees attributable to a new processing contract executed in November 2012 with a significant customer.

Operating costs and expenses. Total operating costs and expenses for the period from November 13 to December 31, 2012 were $34.0 million, which represents a 10% increase compared to the average monthly operating costs and expenses for the year ended December 31, 2011. The most significant component of this increase in both segments was higher allocated general and administrative expenses attributable to approximately $2.3 million of transaction expenses related to the acquisition of the Predecessor Entities on November 13, 2012, as well as approximately $1.0 million of transition services and employee retention costs associated with the acquisition. In addition, depreciation and amortization was higher in both segments in the period from November 13 to December 31, 2012 due to the higher cost basis of property, plant and equipment as a result of the acquisition of the Predecessor Entities on November 13, 2012.

Interest income (expense), net. Interest expense represents the imputed interest, amortization of deferred financing costs and amortization of discount on the debt of Tallgrass Development that is related to its acquisition of the Predecessor Entities on November 13, 2012 and is pushed down to the balance sheet of TEP Predecessor. Interest income represents imputed interest on payments received from certain customers for reimbursement of the capital costs we incurred to connect these customers to our system. The level of interest income is decreasing over time as the balances due to us are being repaid.

Texas Margin Taxes. Our 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 being acquired by Tallgrass 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 sources of liquidity for the year ended December 31, 2013 were proceeds from the IPO, borrowings under our revolving credit facility, proceeds from the sale of the Pony Express Assets, and cash generated from operations. We expect our sources of liquidity in the future to include:

cash generated from our operations;

borrowing capacity available under our revolving credit facility; and

future issuances of additional partnership units and debt securities.

We believe that cash on hand, cash generated from operations and availability under our revolving 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 a combination of borrowings under our credit facility and issuances of debt and equity securities.

Our total liquidity as of December 31, 2013 was as follows:

		December 31, 2013 (in thousands)
Cash on hand	$	
Total capacity under the revolving credit facility		500,000
Less: Outstanding borrowings under the revolving credit facility		(135,000)
Less: Letters of credit issued under the revolving credit facility		(654)
Available capacity under the revolving credit facility		364,346
Total liquidity	$	364,346

Initial Public Offering

On May 17, 2013, we closed our IPO, issuing 14,600,000 common units to the public 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 us from the sale of the common units were approximately $295.9 million, net of the underwriters discount. In addition, we incurred $5.4 million of other costs associated with the IPO, including legal, accounting, printing and consulting fees, resulting in total net proceeds of $290.5 million.

In connection with the IPO, TD contributed 100% of the membership interests in TIGT and TMID to us in exchange for (i) 9,700,000 common units, inclusive of the remaining 407,500 overallotment units not issued to the underwriters, and 16,200,000 subordinated units, (ii) our 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. In addition, we distributed to TD a payment equal to the net proceeds from the issuance of the overallotment units to the underwriters, of approximately $31.2 million, also as a reimbursement for a portion of the capital expenditures made by TD to purchase the contributed assets. At the closing of the IPO, we used the total proceeds, net of the underwriters discount, of approximately $295.9 million to repay approximately $295.9 million of the debt assumed from TD.

Revolving Credit Facility

On May 17, 2013, in connection with the closing of the IPO, we 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 May 17, 2018. On the closing date of the IPO, we borrowed $231.0 million under the credit facility, the proceeds of which were used to (i) repay the remaining approximately $104.1 million of debt assumed from TD; (ii) pay a distribution to TD of $31.2 million, equal to the net proceeds from the exercise of the underwriter s option to purchase additional units (iii) pay $85.5 million to TD as reimbursement for a portion of the capital expenditures made by TD to purchase the contributed assets and (iv) pay origination fees related to the new revolving credit facility and certain other fees associated with the IPO, and fund our working capital requirements. 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.

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The credit facility has an accordion feature that will allow us to increase the available revolving borrowings under the credit facility by up to an additional $100 million, subject to our 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.

Our obligations under the credit facility are (i) guaranteed by us and each of our existing and subsequently acquired or organized direct or indirect wholly-owned domestic subsidiaries, subject to our ability to designate certain of our subsidiaries as Unrestricted Subsidiaries and (ii) secured by a first priority lien on substantially all of the present and after acquired property owned by us and each guarantor (other than real property interests related to TEP s pipelines). Currently, no subsidiaries have been designated as Unrestricted Subsidiaries.

The credit facility contains various covenants and restrictive provisions that, among other things, limit or restrict our ability (as well as the ability of our 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 from taking such action, change the nature of our 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. The credit facility requires us to maintain 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 our 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 September 30, 2013, 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 our total leverage ratio. The unused portion of the credit facility is subject to a commitment fee, which is initially 0.375%, and after September 30, 2013, is either 0.375% or 0.500%, based on our total leverage ratio. As of December 31, 2013, the weighted average interest rate on outstanding borrowings was 2.52%.

Working Capital

Working capital is the amount by which current assets exceed current liabilities. As of December 31, 2013, we had a working capital deficit of $31.9 million compared to a working capital deficit of $43.8 million at December 31, 2012, which represents a decrease in the working capital deficit of $11.9 million.

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 decrease in the working capital deficit from December 31, 2012 to December 31, 2013 was primarily attributable to (i) $17.0 million of other current assets consisting of pending reimbursements from TD at December 31, 2013 for costs incurred by TIGT to construct the Replacement Gas Facilities in connection with the Pony Express Abandonment; (ii) an increase in trade receivables of $9.8 million; (iii) $4.0 million related to the current portion of the long-term debt allocated from TD at December 31, 2012, which was repaid in the second quarter of 2013 upon consummation of the IPO; (iv) increased inventory balances of $2.9 million; (v) partially offset by an increase in net related party payable balances of $12.2 million as all payable and receivable balances between TEP and TD are cash settled subsequent to May 17, 2013, and an overall increase in accounts payable and accrued liabilities of $8.6 million, primarily driven by accruals for capital expenditures.

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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		TEP Pre-Predecessor	
	Year Ended December 31, 2013	Period from November 13 to December 31, 2012	Period from January 1 to November 12, 2012	Year Ended December 31, 2011
	(in thousands)		(in thousands)	
Net cash provided by (used in):				
Operating activities	$ 83,666	$ 10,705	$ 81,335	90,505
Investing activities	$ 30,770	$ (12,687)	$ (21,692)	(9,960)
Financing activities	$ (114,436)	$	$ (57,661)	(80,545)

Operating Activities. Cash flows provided by operating activities were $83.7 million for the year ended December 31, 2013, which is generally consistent with cash flows provided of $81.3 million and $10.7 million for the period January 1, 2012 through November 12, 2012 and the period November 13, 2012 through December 31, 2012, respectively.

Cash flows provided by operating activities were $81.3 million and $10.7 million for the period January 1, 2012 through November 12, 2012 and the period November 13, 2012 through December 31, 2012, respectively, which is generally consistent with $90.5 million of cash flow provided by operating activities for the year ended December 31, 2011.

Net income was $27.4 million lower in the 2012 periods compared to 2011, which was primarily attributable to decreases in natural gas collections from customers and natural gas sales in the Gas Transportation and Storage segment, as well as lower NGLs prices in the Processing segment, both of which are more fully described in Results of Operations in this MD&A. In addition, the one-time sale of 2.0 Bcf of natural gas from storage in the third quarter of 2011 generated approximately $7.0 million of net income that is reported as a cash flow from investing activities.

Investing Activities. Cash flows provided by investing activities were $30.8 million for the year ended December 31, 2013, compared to cash flows used in investing activities of $21.7 million and $12.7 million for the period January 1, 2012 through November 12, 2012 and the period November 13, 2012 through December 31, 2012, respectively. Cash flows provided by investing activities for the year ended December 31, 2013 consisted of cash inflows of $82.7 million for the disposal of property, plant and equipment primarily associated with the sale of the Pony Express Assets in December 2013, offset by capital expenditures of $50.6 million and cash contributed to an equity method affiliate of $1.3 million. Capital expenditures for the year ended December 31, 2013 consisted primarily of the capacity expansion and efficiency upgrade projects at TMID, and to a lesser extent, capital expenditures at TIGT.

For the year ended December 31, 2012, expansion capital projects were approximately $23.1 million. Approximately $9.8 million of this amount was incurred for initial engineering, permitting, hydraulic studies and right-of way acquisitions for the Pony Express Abandonment and was settled pursuant to the centralized cash management program in place at the time. In the Midstream segment, we spent approximately $7.5 million to increase the capacity and efficiency of our Douglas processing plant in order to accommodate our customers increasing natural gas production in the region. In addition, we settled and paid a dispute related to the construction of West Frenchie Draw treating plant in the amount of $5.9 million.

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Cash flows used in investing activities were $21.7 million and $12.7 million for the period from January 1, 2012 to November 12, 2012 and the period from November 13, 2012 to December 31, 2012, respectively, compared to $9.9 million in the year ended December 31, 2011. Capital expenditures consist of maintenance capital expenditures and expansion capital expenditures.

Maintenance capital expenditures are somewhat consistent from period-to-period. However, during 2011 we incurred higher levels of maintenance capital expenditures because of a replacement pipe program on the TIGT System, which was substantially complete by June 2013, and the expansion project at the Casper and Douglas plants, which was substantially completed in the second half of 2013. Maintenance capital expenditures on our assets occur on a regular schedule, but most major maintenance projects are not required every year so the level of maintenance capital expenditures naturally varies from period-to-period.

For the year ended December 31, 2011, we incurred expansion capital expenditures of $9.3 million. The most significant projects in the Gas Transportation and Storage segment were the completion of an expansion of the capacity of our natural gas pipeline facilities that run from Franklin to Hastings, Nebraska and an increase in the capacity of our natural gas storage facility. We spent approximately $15.7 million on the pipeline expansion and approximately $7.3 million on the gas storage project in 2010. The remaining expenditures on these projects in 2011 were approximately $4.8 million. In the Processing segment, we spent approximately $3.1 million in 2011 on a project to transport NGLs to a refinery near our Casper processing plant.

Financing Activities. Cash flows used in financing activities of $114.4 million for the year ended December 31, 2013 consisted of net distributions to TD of $118.5 million for the period from January 1, 2013 to May 17, 2013 in addition to distributions paid to unitholders of $18.2 million during the period from May 17, 2013 to December 31, 2013, and the proceeds, net of expenses, associated with the IPO and the associated debt transactions. Gross proceeds from the IPO totaled $313.9 million, and were partially offset by costs incurred in connection with the IPO of $23.4 million. In addition, cash flows provided by financing activities reflect a net outflow of $270.2 million related to the associated debt transactions, including the repayment of $400.0 million of debt assumed from TD, partially offset by net borrowings under the revolving credit facility of $135.0 million and payments for deferred financing costs of $5.2 million.

Cash flows used in financing activities of $57.7 million and $80.5 million for the period from January 1, 2012 to November 12, 2012 and for the year ended December 31, 2011, respectively, consisted entirely of net distributions. There were no cash flows from financing activities for the period from November 13, 2012 to December 31, 2012. Prior to November 13, 2012, cash flows used in financing activities consisted entirely of cash distributions paid to the TEP Pre-Predecessor Parent, as TEP Pre-Predecessor participated in its parent 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. 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. Beginning on May 17, 2013, TEP maintains the cash balances of TIGT and TMID. As a result, the practice of settling and distributing these balances as equity distributions to TD was discontinued on that date.

Distributions

We intend to pay quarterly distributions at or above the amount of the MQD, which is $0.2875 per unit. As of March 1, 2014, we had a total of 41,326,531 common, subordinated and general partner units outstanding, which equates to an aggregate MQD of approximately $11.9 million per quarter, or $47.5 million per year. We do not have a legal obligation to pay distributions except as provided in our partnership agreement.

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The following table shows the distributions for the year ended December 31, 2013:

Three Months Ended	Date Paid	Limited Partners Common and Subordinated	Distributions General Partner Incentive	2%	Total	Distributions per Limited Partner Unit
		(in thousands, except per unit amounts)				
December 31, 2013	February 12, 2014	$ 12,757	$ 63	$ 262	$ 13,082	$ 0.3150
September 30, 2013	November 13, 2013	12,049		245	12,294	0.2975
June 30, 2013 (1)	August 13, 2013	5,759		118	5,877	0.1422(1)
March 31, 2013	N/A	N/A	N/A	N/A	N/A	N/A

(1) The distribution declared on July 18, 2013 for the second quarter of 2013 represented a prorated amount of our MQD of $0.2875 per common unit, based upon the number of days between the closing of the IPO on May 17, 2013 to June 30, 2013.

Capital Requirements

Our business is capital-intensive, requiring significant investment to maintain and improve existing assets. We currently expect to spend approximately $44 million for capital expenditures at TIGT and TMID during 2014, with approximately $29 million being related to the Replacement Gas Facilities and other costs associated with the Pony Express Abandonment, for which we will receive reimbursement from TD. The remaining approximately $15 million is related to maintenance and expansion capital expenditures, with $10 million to $13 million currently being estimated for maintenance capital expenditures.

Contractual Obligations

Following is a summary of our contractual cash obligations over the next several fiscal years, representing amounts that were fixed and determinable as of December 31, 2013:

Contractual Obligations	Total	Payments Due By Period Less Than 1 Year	1-3 Years	4-5 Years	More Than 5 Years
Debt obligations (1)	$ 135,000	$ 0	$ 0	$ 135,000	$ 0
Interest on debt obligations (2)	16,575	3,406	6,813	6,356	0
Operating lease and service contract obligations (3)	962	259	456	182	65
Land site lease and right-of-way (4)	1,048	104	239	217	488
Other purchase commitments (5)	1,932	1,932	0	0	0
Total	$ 155,517	$ 5,701	$ 7,508	$ 141,755	$ 553

(1) Debt obligations at December 31, 2013 consisted of borrowings under the revolving credit facility. For additional information, see Note 8 Long-Term Debt to the Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data.

(2) Interest on debt obligations is estimated using current borrowings and interest rates as of December 31, 2013. For additional information, see Note 9 Commitments and Contingent Liabilities to the Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data.

(3) Operating leases and service contracts consist of leases for office space and equipment.

(4) Land site lease and right-of-way contracts consist of payments to landowners, primarily in our Gas Transportation and Storage segment. For additional information, see Note 9 Commitments and Contingent Liabilities to the Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data.

(5) Other purchase commitments primarily relate to planned non-reimbursable capital expenditures.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Critical Accounting Policies and Estimates

Our significant accounting policies are described in Note 2 *Summary of Significant Accounting Policies* to the consolidated financial statements included in Item 8 of this Annual Report. Management s discussion and analysis of financial condition and results of operations are based upon our financial statements, which have been prepared in accordance with GAAP. 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 accounting policies discussed below 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. For additional information concerning our other accounting policies, please read the notes to the financial statements included in this report.

Revenue Recognition

We recognize revenues when services are rendered or goods are sold to a purchaser at a fixed and determinable price, delivery has occurred, title has transferred and collectability is reasonably assured.

NGL sales occur in the processing segment and consist of the sale of outputs from our processing plants and the marketing of NGLs that are purchased from our suppliers.

Natural gas sales occur in both the Gas Transportation and Storage segment and in the Processing segment. In the Gas Transportation and Storage segment, natural gas sales occur when a portion of the natural gas transported by customers is collected as a contractual fee to compensate us for fuel consumed by pipeline and storage operations. These volumes of gas that are retained from our customers are recorded as transportation services revenue when received and injected into storage and the volumes, when subsequently sold, are recorded as natural gas sales revenue and cost of sales and transportation services. In addition, when operational conditions allow, we occasionally sell cushion gas, which refers to the minimum volume of natural gas required in order to operate the storage facility. In the Processing segment, we purchase natural gas primarily for use in our operations and for meeting contractual requirements to deliver natural gas to certain customers. In addition, some of our contractual arrangements allow us to keep a portion of the processed natural gas as compensation for processing services. We generate revenue by selling the volumes of natural gas received or purchased that exceed our contractual and operational requirements.

Transportation services occur in the Gas Transportation and Storage segment. In many cases (generally described as firm service), the customer pays a two-part rate that includes (i) a fee reserving the right to transport or store natural gas in our facilities and (ii) a per-unit rate for volumes actually transported or injected into/withdrawn from storage. The fee-based component of the overall rate is recognized as revenue in the period the service is provided. The per-unit charge is recognized as revenue when the volumes are delivered to the customer s agreed upon delivery point, or when the volumes are injected into or withdrawn from our storage facilities. In other cases (generally described as interruptible service), there is no fee associated with the services because the customer accepts the possibility that service may be interrupted at our discretion in order to serve customers who have purchased firm service. In the case of interruptible service, revenue is recognized in the same manner utilized for the per-unit rate for volumes actually transported under firm service agreements. In addition to our firm and interruptible transportation services, we provide natural gas park and loan services to assist customers in managing short-term gas surpluses or deficits. Revenues are recognized as services are provided, based on the terms negotiated under these contracts.

Processing and other revenues primarily represent processing fees earned in the Processing segment.

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Accounting for Regulatory Activities

Our regulated activities are accounted for in accordance with the Regulated Operations topic of the Financial Accounting Standards Board Accounting Standard Codification, which we refer to as the Codification. The Regulated Operations topic prescribes the circumstances in which the application of GAAP is affected by the economic effects of regulation. Regulatory assets and liabilities represent probable future revenues or expenses associated with certain charges and credits that will be recovered from or refunded to customers through the ratemaking process.

Property, Plant and Equipment

Property, plant and equipment is stated at historical cost, which for constructed plants includes indirect costs such as payroll taxes, other employee benefits, allowance for funds used during construction for regulated assets and other costs directly related to the projects. Expenditures that increase capacities, improve efficiencies or extend useful lives are capitalized. Routine maintenance, repairs and renewal costs are expensed as incurred. The cost of normal retirements of the regulated depreciable utility property, plant and equipment, plus the cost of removal less salvage value, is recorded in accumulated depreciation with no effect on current period earnings. Gains or losses are recognized upon retirement of utility property, plant and equipment constituting an operating unit or system, and land, when sold or abandoned.

We review our long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. An impairment loss results when the estimated undiscounted future net cash flows expected to result from the asset s use and its eventual disposition are less than its carrying amount and would be recognized upon regulatory approval.

Commitments and Contingencies

We recognize liabilities for other commitments and contingencies when, after fully analyzing the available information, we determine it is probable that a liability has been incurred and the amount of loss can be reasonably estimated. When a range of probable loss can be estimated, we accrue the most likely amount, or if no amount is more likely than another, we accrue the minimum of the range of probable loss.

Environmental Costs

TEP and TEP Pre-Predecessor expense or capitalize, as appropriate, environmental expenditures that relate to current operations. TEP and TEP Pre-Predecessors expense amounts that relate to an existing condition caused by past operations that do not contribute to current or future revenue generation. TEP and TEP Pre-Predecessor do not discount environmental liabilities to a net present value, and record environmental liabilities when environmental assessments and/or remedial efforts are probable and costs can be reasonably estimated. Recording of these accruals coincides with the completion of a feasibility study or a commitment to a formal plan of action. Estimates of environmental liabilities are based on currently available facts and presently enacted laws and regulations taking into consideration the likely effects of other factors including our prior experience in remediating contaminated sites, other companies clean-up experience and data released by government organizations. Our estimates are subject to revision in future periods based on actual cost or new information.

Risk Management Activities

We enter into derivative contracts with third parties for the purpose of hedging exposures that accompany our natural gas purchases and sales in our Gas Transportation and Storage segment, which expose us to risks associated with changes in the market price of natural gas and NGLs. Specifically, these risks are associated with (i) pre-existing or anticipated physical natural gas sales, (ii) natural gas purchases; and (iii) natural gas system use and storage. During the period from January 1, 2012 to December 31, 2012, we recognized no gain or loss as a result of ineffectiveness of these hedges. We did not exclude any component of the derivative contracts gain or loss from the assessment of hedge effectiveness. As the hedged sales and purchases took place and we recorded them into earnings, we also reclassified the associated gains and losses included in accumulated other comprehensive income into earnings. Subsequent to November 13, 2012, we discontinued the use of hedge accounting and began recording the changes in fair value of our derivative contracts in current earnings. We do not currently hedge the commodity exposure in our processing contracts with respect to our natural gas and NGL purchases and sales in our Processing segment. However, we monitor the mix of our contractual arrangements described above and expect to continue to increase the fee-based component of our contract portfolio when practical in order to reduce our exposure to natural gas and NGL price volatility.

Goodwill

We evaluate goodwill for impairment annually in the third quarter, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount.

We evaluate goodwill impairment by reporting unit level, which is an operating segment as defined in the segment reporting guidance of the Codification, using either the qualitative assessment option or the two-step test approach depending on facts and circumstances of the reporting unit. Our reporting units are the same as our reporting segments. If we, after performing the qualitative assessment, determine it is more likely than not that the fair value of a reporting unit is greater than its carrying amount, the two-step impairment test is unnecessary. When goodwill is evaluated for impairment using the two-step test, the carrying amount of the reporting unit is compared to its fair value in Step 1 and if the fair value exceeds the carrying amount, Step 2 is unnecessary. If the carrying amount exceeds the reporting unit s fair value, this could indicate potential impairment and Step 2 of the goodwill evaluation process is required to determine if goodwill is impaired and to measure the amount of impairment loss to recognize, if any. When Step 2 is necessary, the fair value of individual assets and liabilities is determined using valuations, or other observable sources of fair value, as appropriate. If the carrying amount of goodwill exceeds its implied fair value, the excess is recognized as an impairment loss.

We completed our impairment testing of goodwill in the third quarter of 2013 using the methodology described herein, and determined there was no impairment.

Equity-Based Compensation

Equity-based compensation grants are measured at their grant date fair value and related compensation cost is recognized over the vesting period of the grant. Compensation cost for awards with graded vesting provisions is recognized on a straight-line basis over the requisite service period of each separately vesting portion of the award.

Estimating the fair value of each award, the number of awards that will ultimately vest, and the forfeiture rate requires management to apply judgment to estimate the tenure of our employees and the achievement of certain performance targets over the performance period. If actual results are not consistent with our assumptions and judgments or our assumptions and estimates change due to new information, we may experience material changes in compensation expense.

Emerging Growth Company

We are an emerging growth company pursuant to the JOBS Act. The JOBS Act provides that an emerging growth company may delay adopting new or revised accounting standards until such time as those standards apply to private companies. We have elected to take advantage of this exemption and, therefore, may adopt new or revised accounting standards at the time those standards apply to private companies. As a result of our election to take advantage of this transition period, our financial statements may not be comparable to those of companies that comply with public company effective dates for the adoption of new or revised accounting standards. This election had no material impact on the consolidated financial statements included in this Annual Report.

Item 7A. 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. As of December 31, 2013, approximately 66% of our reserved capacity was subject to fee-based contracts, with the remaining 34% subject to percent of proceeds or keep whole contracts, a notable recent shift toward fee-based contracts as compared to approximately 34% fee-based contracts and approximately 66% of percent of proceeds or keep whole contracts as of December 31, 2012. We do not currently hedge the commodity exposure in our processing contracts and we do not expect to in the foreseeable future. We have addressed, and will consider future opportunities to address, the commodity exposure in our processing segment by continuing to convert our processing contracts that are keep whole or percent of proceeds to primarily fee based contracts. The weighted average contract term for all processing contracts is approximately four years.

We also have a limited amount of direct commodity price exposure related to natural gas collected 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 a substantial majority of the gas we expect to collect during the current year for the purpose of hedging our commodity price exposures. We expect to continue these hedging activities for the foreseeable future. As of December 31, 2013, we had natural gas swaps outstanding with a notional volume of approximately 0.8 Bcf, representing a portion of the natural gas that is expected to be sold by our Gas Transportation and Storage segment in 2014. The fair value of these swaps was a liability of approximately $0.2 million at December 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 10% 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. The aggregate effect of a hypothetical 10% increase in the natural gas price forward curve would be a decrease of approximately $0.3 million in the net fair value of our derivative instruments.

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.

The CFTC has promulgated regulations to implement Dodd-Frank s changes to the Commodity Exchange Act, including the definition of commodity-based swaps subject to those regulations. The CFTC regulations are intended to implement new reporting and record keeping requirements related to their swap transactions and a mandatory clearing and exchange-execution regime for various types, categories or classes of swaps, subject to certain exemptions, including the trade-option and end-user exemptions. Although we anticipate that most, if not all, of our swap transactions should qualify for an exemption to the clearing and exchange-execution requirements, we will still be subject to record keeping and reporting requirements. Other changes to the Commodity Exchange Act made as a result of the Dodd-Frank Act and the CFTC s implementing regulations could significantly increase the cost of entering into new swaps.

Interest Rate Risk

As described in Liquidity and Capital Resources Overview above, at the closing of the IPO, 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 was initially 1.00%, and for loans bearing interest based on the reserve adjusted Eurodollar rate, the applicable margin was initially 2.00%. After September 30, 2013, the applicable margin ranges 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 do not currently hedge the interest rate risk on our borrowings under the credit facility. However, in the future we may consider hedging the interest rate risk or may consider choosing longer Eurodollar borrowing terms in order to fix all or a portion of our borrowings for a period of time. We estimate that a 1% increase in interest rates would decrease the fair value of the debt by $0.1 million based on the debt obligations as of December 31, 2013.

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 December 31, 2013.

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Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

To the Partners of Tallgrass Energy Partners, LP:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, partners capital and cash flows present fairly, in all material respects, the financial position of Tallgrass Energy Partners, LP and its subsidiaries (the Partnership) at December 31, 2013 and 2012, and the results of their operations and their cash flows for the year ended December 31, 2013 and for period from November 13, 2012 to December 31, 2012 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Partnership s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Denver, Colorado

March 11, 2014

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Report of Independent Registered Public Accounting Firm

To the Partners of Tallgrass Energy Partners, LP:

In our opinion, the accompanying statements of income, comprehensive income, partners capital and cash flows present fairly, in all material respects, Tallgrass Energy Partners Pre-Predecessor s (TEP Pre-Predecessor) results of operations and their cash flows for the period from January 1, 2012 to November 12, 2012 and the year ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the TEP Pre-Predecessor management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Denver, Colorado

March 18, 2013

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TALLGRASS ENERGY PARTNERS, LP

CONSOLIDATED BALANCE SHEETS

	December 31, 2013	December 31, 2012
	(in thousands)	
ASSETS		
Current Assets:		
Accounts receivable, net	$ 27,615	$ 17,848
Accounts receivable from related parties		6,463
Gas imbalances	2,598	1,282
Inventories	5,148	2,204
Derivative assets at fair value		224
Prepayments and other current assets	16,986	47
Total Current Assets	52,347	28,068
Property, plant and equipment, net	594,911	669,476
Goodwill	304,474	301,852
Deferred financing costs	4,512	
Deferred financing costs allocated from TD		13,352
Deferred charges and other assets	11,554	23,066
Total Assets	$ 967,798	$ 1,035,814
LIABILITIES AND PARTNERS CAPITAL		
Current Liabilities:		
Accounts payable	$ 54,621	$ 35,496
Accounts payable to related parties	7,134	
Notes payable to related parties		1,387
Gas imbalances	3,142	1,250
Derivative liabilities at fair value	184	23
Accrued taxes	4,427	3,465
Current portion of long-term debt allocated from TD		4,000
Accrued other current liabilities	14,777	26,233
Total Current Liabilities	84,285	71,854
Long-term debt	135,000	
Long-term debt allocated from TD		390,491
Other long-term liabilities and deferred credits	4,572	1,635
Total Long-term Liabilities	139,572	392,126
Commitments and Contingencies (Notes 9 and 15)		
Partners Capital:		
Common unitholders (24,300,000 units issued and outstanding at December 31, 2013)	455,197	
	274,666	

Subordinated unitholder (16,200,000 units issued and outstanding at December 31, 2013)		
General partner (826,531 units issued and outstanding at December 31, 2013)	14,078	
Member s Capital		571,834
Total Partners Capital	743,941	571,834
Total Liabilities and Partners Capital	$ 967,798	$ 1,035,814

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

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TALLGRASS ENERGY PARTNERS, LP

CONSOLIDATED STATEMENTS OF INCOME (LOSS)

	TEP		TEP Pre-Predecessor	
	Year Ended December 31, 2013	Period from November 13 to December 31, 2012	Period from January 1 to November 12, 2012	Year Ended December 31, 2011
	(in thousands, except per unit amounts)		(in thousands, except per unit amounts)	
Revenues:				
Natural gas liquids sales	$ 146,313	$ 18,554	$ 106,355	$ 151,627
Natural gas sales	7,969	1,910	15,634	28,339
Transportation services	98,625	13,102	93,214	123,018
Processing and other revenues	14,801	1,722	5,089	4,059
Total Revenues	267,708	35,288	220,292	307,043
Operating Costs and Expenses:				
Cost of sales and transportation services (exclusive of depreciation and amortization shown below)	137,285	18,298	101,452	150,120
Operations and maintenance	31,945	3,353	29,901	33,294
Depreciation and amortization	29,549	4,086	20,647	22,726
General and administrative	21,894	7,133	11,318	16,044
Taxes, other than income taxes	6,325	1,107	6,861	9,360
Total Operating Costs and Expenses	226,998	33,977	170,179	231,544
Operating Income	40,710	1,311	50,113	75,499
Other Income (Expense):				
Interest (expense) income, net	(2,113)	235	1,661	2,101
Interest expense allocated from TD	(9,028)	(3,436)		
Loss on extinguishment of debt	(17,526)			
Other income, net	2,136	482	1	203
Total Other (Expense) Income	(26,531)	(2,719)	1,662	2,304
Income (Loss) Before Income Taxes	14,179	(1,408)	51,775	77,803
Texas Margin Taxes			279	296
Net Income (Loss)	$ 14,179	$ (1,408)	$ 51,496	$ 77,507

Allocation of income for the year ended December 31, 2013:	
Net income attributable to the period from January 1, 2013 to May 16, 2013	$ 6,982
Net income attributable to the period from May 17, 2013 to December 31, 2013	7,197
Net Income	$ 14,179
General partner interest in net income for the period from May 17, 2013 to December 31, 2013	$ 206
Common and subordinated unitholders interest in net income for the period from May 17, 2013 to December 31, 2013	$ 6,991
Basic net income per common and subordinated unit	$ 0.17
Diluted net income per common and subordinated unit	$ 0.17
Basic average number of common and subordinated units outstanding	40,450
Diluted average number of common and subordinated units outstanding	41,458

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

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TALLGRASS ENERGY PARTNERS, LP

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	TEP		TEP Pre-Predecessor	
	Year Ended December 31, 2013	Period from November 13 to December 31, 2012	Period from January 1 to November 12, 2012	Year Ended December 31, 2011
	(in thousands)		(in thousands)	
Net Income (Loss)	$ 14,179	$ (1,408)	$ 51,496	$ 77,507
Other Comprehensive Income:				
Reclassification of change in fair value of derivatives to net income			(4,187)	(3,410)
Change in fair value of derivatives utilized for hedging purposes			1,024	6,146
Total Other Comprehensive (Loss) Income			(3,163)	2,736
Comprehensive Income (Loss)	$ 14,179	$ (1,408)	$ 48,333	$ 80,243

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

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TALLGRASS ENERGY PARTNERS, LP

CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL

				Partners Capital						
				Limited Partners				General Partner		
	TEP Pre-Predecessor Member s Capital	TEP Predecessor Member s Capital	Accumulated Other Comprehensive Income	Common Units	Common Amount	Subordinated Units	Subordinated Amount	Units	Amount	Total
					(in thousands)					
Balance at January 1, 2011	$ 736,755	$	$ 355		$		$		$	$ 737,110
Net income to Member	77,507									77,507
Distributions to Member, net	(80,545)									(80,545)
Total change in fair value of derivatives, including a reclassification to earnings			2,736							2,736
Balance at January 1, 2012	$ 733,717	$	$ 3,091		$		$		$	$ 736,808
Net income to Member	51,496									51,496
Distributions to Member, net	(57,661)									(57,661)
Total change in fair value of derivatives, including a reclassification to earnings			(3,163)							(3,163)
Balance at November 12, 2012	727,552		(72)							$ 727,480
TEP Predecessor s acquisition of TIGT and TMID	$	$ 573,242	$		$		$		$	573,242

Net loss to Member		(1,408)								(1,408)
Balance at December 31, 2012	$	$ 571,834	$		$		$		$	571,834
Net income attributable to the period from January 1, 2013 to May 16, 2013		6,982								6,982
Distributions to Member, net		(118,538)								(118,538)
Contribution of net assets of TIGT and TMID		(460,278)		9,700	167,051	16,200	278,992	827	14,235	
Issuance of units to public (including underwriter over-allotment), net of offering and other costs				14,600	290,483					290,483
Net income attributable to the period from May 17, 2013 to December 31, 2013					4,194		2,797		206	7,197
Distributions to unitholders					(10,685)		(7,123)		(363)	(18,171)
Noncash compensation expense					4,154					4,154
Balance at December 31, 2013	$	$	$	24,300	$ 455,197	16,200	$ 274,666	827	$ 14,078	$ 743,941

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

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TALLGRASS ENERGY PARTNERS, LP

CONSOLIDATED STATEMENTS OF CASH FLOWS

	TEP		TEP Pre-Predecessor	
	Year Ended December 31, 2013	Period from November 13 to December 31, 2012	Period from January 1 to November 12, 2012	Year Ended December 31, 2011
	(in thousands)		(in thousands)	
Cash Flows from Operating Activities:				
Net income (loss)	$ 14,179	$ (1,408)	$ 51,496	$ 77,507
Adjustments to reconcile net income to net cash flows from operating activities:				
Depreciation and amortization	31,295	4,481	20,647	22,726
Loss on extinguishment of debt	17,526			
Noncash compensation expense	1,798			
Changes in components of working capital:				
Accounts receivable and other	5,436	3,271	(3,749)	3,879
Gas imbalances	1,124	(465)	4,551	(4,212)
Inventories	(2,695)	(145)	(98)	(205)
Accounts payable and accrued liabilities	15,907	4,226	6,286	(4,361)
Other, net	(904)	745	2,202	(4,829)
Net Cash Provided by Operating Activities	83,666	10,705	81,335	90,505
Cash Flows from Investing Activities:				
Capital expenditures	(50,642)	(12,631)	(19,540)	(22,788)
Investment in equity method affiliate	(1,255)			
Net cash paid for purchase and sale of gas in underground storage			(2,249)	14,669
Disposal of property, plant and equipment (net of removal costs)	82,667	(56)	97	(1,841)
Net Cash Provided by (Used in) Investing Activities	30,770	(12,687)	(21,692)	(9,960)
Cash Flows from Financing Activities:				
Repayment of debt assumed from TD	(400,000)			
Borrowings under revolving credit facility	135,000			

Payments for deferred financing costs	(5,162)			
Proceeds from initial public offering, net of offering costs	290,483			
Distributions to Member, net	(118,538)		(57,661)	(80,545)
Distributions to unitholders	(18,171)			
Reimbursement of stock compensation expense from TD	1,952			
Net Cash Used in Financing Activities	(114,436)		(57,661)	(80,545)
Net Change in Cash and Cash Equivalents		(1,982)	1,982	
Cash and Cash Equivalents, beginning of period		1,982		
Cash and Cash Equivalents, end of period	$	$	$ 1,982	$
Supplemental Disclosures:				
Cash payments for interest	$ 3,450	$	$	$
Schedule of Noncash Investing and Financing Activities:				
Fair value of TIGT and TMID assets contributed by TD	$ 1,027,127	$	$	$
Fair value of TIGT and TMID liabilities contributed by TD	$ (566,849)	$	$	$
Fair value of TIGT and TMID assets acquired by TEP Predecessor	$	$ 1,028,071	$	$
Fair value of TIGT and TMID liabilities acquired by TEP Predecessor	$	$ (454,829)	$	$
Increase in accrual for reimbursable construction in progress projects	$ 14,470	$	$	$
Increase in accrual for payment of property, plant and equipment	$	$ 5,325	$ 1,939	$
Receivable for unreimbursed stock compensation from TD	$ 404	$	$	$

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

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TALLGRASS ENERGY PARTNERS, LP,

TALLGRASS ENERGY PARTNERS PREDECESSOR

AND TALLGRASS ENERGY PARTNERS PRE-PREDECESSOR

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Description of Business

Tallgrass Energy Partners, LP (TEP) is a Delaware limited partnership formed in February 2013. On May 17, 2013, TEP closed its initial public offering (IPO) 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 the underwriters discount. In addition, TEP recognized $5.4 million of other costs associated with the IPO, including legal, accounting, printing and consulting fees, resulting in total net proceeds of $290.5 million.

In connection with the IPO, Tallgrass Development, LP (TD) contributed 100% of the membership interests in TIGT and TMID (each defined below) to TEP in exchange for (i) 9,700,000 common units, inclusive of the remaining 407,500 overallotment units not issued to the underwriters, and 16,200,000 subordinated units, (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. In addition, a payment of approximately $31.2 million, equal to the net proceeds from the issuance of the overallotment units to the underwriters, was distributed by TEP to TD. At the closing of the IPO, TEP used the total proceeds, net of the underwriters discount, of approximately $295.9 million to repay approximately $295.9 million of the debt assumed from TD.

The 14,600,000 common units held by the public constitute approximately 36% of TEP s outstanding common and subordinated units and approximately 35% of TEP s outstanding common, subordinated and general partner units. TD s 9,700,000 common units and 16,200,000 subordinated units comprise approximately 64% of TEP s outstanding common and subordinated units and approximately 63% of TEP s outstanding common, subordinated and general partner units. In addition, as part of the contribution transaction, 826,531 general partner units, representing a 2% general partner interest in TEP, and all of our IDRs were issued to Tallgrass MLP GP, LLC (the GP). In connection with the IPO, 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. For additional information, see Note 10 *Partnership Equity and Distributions*.

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 (TEP Pre-Predecessor Parent) prior to November 13, 2012. On November 13, 2012, TEP Pre-Predecessor Parent sold those assets, among others, to TD. The Predecessor Entities are referred to as TEP Predecessor for the period in which they were owned by TD, from November 13, 2012 through the completion of the IPO on May 17, 2013, and as TEP Pre-Predecessor for periods in which they were owned by TEP Pre-Predecessor Parent, 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 4,645 miles of varying diameter natural gas transmission lines in Colorado, Kansas, Missouri, Nebraska and Wyoming. In 2013, TIGT sold 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 6 *Property, Plant and Equipment* and Note 14 *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 KM Upstream LLC.

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

2. Summary of Significant Accounting Policies

Basis of Presentation

The accompanying financial statements and related notes were prepared in accordance with the accounting principles contained in the Financial Accounting Standards Board s Accounting Standards Codification, the single source of generally accepted accounting principles in the United States of America (GAAP). 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. Certain prior period amounts have been reclassified to conform to the current presentation.

The accompanying combined financial statements for TEP Predecessor as of December 31, 2012 and for the period from November 13, 2012 to December 31, 2012, and for TEP Pre-Predecessor for the period from January 1, 2012 to November 12, 2012, are presented on a held in use basis. The accompanying consolidated financial statements of TEP include historical cost-basis accounts of the assets of TEP Predecessor, contributed to us by TD in connection with the IPO for the periods prior to May 17, 2013, the closing date of TEP s IPO, and include charges from TD for direct costs and allocations of indirect corporate overhead. Management believes that the allocation methods are reasonable, and that the allocations are representative of costs that would have been incurred on a stand-alone basis. Both TEP and TEP Predecessor are considered entities under common control as defined under GAAP and, as such, the transfer between the entities of the assets and liabilities has been recorded by TEP at historical cost. TEP, or the Partnership, as used herein refers to the consolidated financial results and operations for TEP Predecessor from its inception through its contribution to TEP and thereafter.

The 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 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 Consolidated Statements of Partners Capital and Combined Statement of Cash Flows represent transfers of cash as a result of TD and TEP Pre-Predecessor Parent s centralized cash management systems prior to May 17, 2013, under which cash balances were swept daily and recorded as loans from the subsidiaries to TD. These loans were then periodically recorded as equity distributions.

TEP s financial results as presented on the consolidated statements of income (loss), comprehensive income and cash flows have been separated from TEP Pre-Predecessor s combined financial results by a bold vertical black line.

Use of Estimates

Certain amounts included in or affecting these consolidated 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 TEP or 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.

Cash and Cash Equivalents

TEP and the TEP Pre-Predecessor consider all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Prior to November 12, 2012, the TEP Pre-Predecessor Parent employed a centralized cash management system that was utilized for its wholly-owned subsidiaries. Subsequent to November 13, 2012, TIGT and TMID entered into similar cash management agreements with TD. In accordance with the cash management agreements, the subsidiary companies make loans on each business day equal to the amount swept from their depository bank accounts. At the beginning of the following month, the total of these loans for each company, less reimbursement payments under the agency agreements described below in Note 4 *Related Party Transactions*, is transferred to an interest bearing account and are subsequently, periodically recorded as equity distributions. This practice was discontinued effective May 17, 2013, when TIGT and TMID were contributed to TEP. Subsequent to May 17, 2013, all payable and receivable balances between TEP and TD are cash settled.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are carried at their estimated collectible amounts. TEP and TEP Pre-Predecessor make periodic reviews and evaluations of the appropriateness of the allowance for doubtful accounts based on a historical analysis of uncollected amounts, and adjustments are recorded as necessary for changed circumstances and customer-specific information. When specific receivables are determined to be uncollectible, the reserve and receivable are relieved. Our allowance for doubtful accounts totaled $0.8 million at December 31, 2013 and 2012.

Inventories

Inventories primarily consist of natural gas liquids, materials and supplies, and gas in underground storage. Natural gas liquids and gas in underground storage are recorded at the lower of historical cost or market. Materials and supplies are valued at weighted average cost and periodically reviewed for physical deterioration and obsolescence. For additional information, see *Gas in Underground Storage* below.

Accounting for Regulatory Activities

Regulated activities are accounted for in accordance with the Regulated Operations Topic of the Codification. This Topic prescribes the circumstances in which the application of GAAP is affected by the economic effects of regulation. Regulatory assets and liabilities represent probable future revenues or expenses to TEP and TEP Pre-Predecessor associated with certain charges and credits that will be recovered from or refunded to customers through the ratemaking process. TEP had recorded regulatory assets of approximately $0.3 million included in Deferred charges and other assets in the Consolidated Balance Sheets at December 31, 2013 and 2012, respectively. Regulatory assets at December 31, 2013 were primarily attributable to costs associated with the Predecessor Entities participation in the TEP Pre-Predecessor entity s postemployment benefit plans. Regulatory assets at December 31, 2012 were primarily attributable to unamortized FERC annual charge adjustments and costs associated with the

Predecessor entities participation in the TEP Pre-Predecessor Entity s postemployment benefit plans.

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Property, Plant and Equipment

Property, plant and equipment for TEP was adjusted to fair value on November 13, 2012, the date the acquisition of TIGT and TMID by TEP was completed. For additional information see Note 3 *Business Combinations*.

Expenditures that increase capacities, improve efficiencies or extend useful lives are capitalized and depreciated over the remaining useful life of the asset or major asset component. We also capitalize certain costs directly related to the construction of assets, including internal labor costs, interest and engineering costs.

Routine maintenance, repairs and renewal costs are expensed as incurred. The cost of normal retirements of the regulated depreciable utility property, plant and equipment, plus the cost of removal less salvage value and any gain or loss recognized, is recorded in accumulated depreciation with no effect on current period earnings. Gains or losses are recognized upon retirement of non-regulated or regulated property, plant and equipment constituting an operating unit or system, and land, when sold or abandoned and costs of removal or salvage are expensed when incurred.

Impairment of Long-Lived Assets

TEP and TEP Pre-Predecessor review their long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. An impairment loss results when the estimated undiscounted future net cash flows expected to result from the asset s use and its eventual disposition are less than its carrying amount. Any such impairment losses at TIGT would be recorded as a regulatory asset until regulatory review regarding recoverability through the rate-making process is complete, at which time TIGT will recognize the loss if it is determined to be unrecoverable or retain as a regulatory asset and recover through their rates.

TEP and TEP Pre-Predecessor assess their long-lived assets for impairment in accordance with the relevant Codification guidance. A long-lived asset is tested for impairment whenever events or changes in circumstances indicate its carrying amount may exceed its fair value.

Examples of long-lived asset impairment indicators include:

- a significant decrease in the market value of a long-lived asset or group;
- a significant adverse change in the extent or manner in which a long-lived asset or asset group is being used or in its physical condition;
- a significant adverse change in legal factors or in the business climate could affect the value of long-lived asset or asset group, including an adverse action or assessment by a regulator which would exclude allowable costs from the rate-making process;
- an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of the long-lived asset or asset group;

a current period operating cash flow loss combined with a history of operating cash flow losses or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset or asset group; and

a current expectation that, more likely than not, a long-lived asset or asset group will be sold or otherwise disposed of significantly before the end of its previously estimated useful life.

When an impairment indicator is present, TEP and TEP Pre-Predecessors first assess the recoverability of the long-lived assets by comparing the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset to the carrying amount of the asset. If the carrying amount is higher than the undiscounted future cash flows, the fair value of the assets is assessed using a discounted cash flow analysis and used to determine the amount of impairment, if any, to be recognized.

Gas in Underground Storage

Gas in underground storage represents the cost of base gas and cushion gas, which refers to the volumes necessary to maintain pressure and deliverability requirements in TEP and TEP Pre-Predecessors storage facilities. TEP and TEP Pre-Predecessor record base gas and cushion gas as a component of property, plant and equipment.

TEP maintains working gas in its underground storage facilities on behalf of certain third parties. TEP receives a fee for its storage services but does not reflect the value of third party gas in the accompanying consolidated financial statements. TEP occasionally acquires volumes of working gas for its own account. These volumes of working gas are recorded as natural gas inventory at the lower of cost of market. Prior to November 12, 2012, TEP Pre-Predecessor recorded these volumes of working gas at historical cost as a component of property, plant and equipment.

Depreciation and Amortization

TEP Pre-Predecessor computed depreciation using a composite method employed by applying a single depreciation rate to a group of assets with similar economic characteristics. This composite method of depreciation approximates a straight-line method of depreciation. TEP has elected to continue to use the composite depreciation method for its regulated assets at TIGT. The annualized rate of depreciation at TIGT ranges from 2.50% to 12.00% for the various classes of depreciable, regulated assets. For non-regulated assets at TMID, TEP has elected to use the straight-line method of depreciation. The useful lives for the various classes of depreciable assets at TMID are as follows:

	Range of Useful Lives (in years)
Processing & Treating	30
Vehicles	10
General & Other	3 -13 1/3

Gas Imbalances

Gas imbalances receivable and payable represent the difference between customer nominations and actual gas receipts from and gas deliveries to interconnecting pipelines under various operational balancing and imbalance agreements. Gas imbalances are either made up in-kind or settled in cash, subject to the terms and valuations of the various agreements. Imbalances are valued at the Average Monthly Index Price (AMIP) of the Colorado Interstate Gas Index (CIG) and Panhandle Eastern Pipeline (PEPL).

Deferred Financing Costs

Costs incurred in connection with the issuance of long-term debt are deferred and amortized over the related financing period using the effective interest method.

Deferred financing costs were allocated from TD to TEP on November 13, 2012 as discussed in Note 3 *Business Combinations*. Deferred financing costs allocated from TD were amortized over the related financing period using the effective interest method and subsequently written off as a loss on extinguishment of debt upon repayment of the long-term debt allocated from TD on May 17, 2013. See Note 8 *Long-term Debt* for additional information.

Goodwill

As discussed in Note 3 *Business Combinations*, we recorded $301.9 million of goodwill in connection with the acquisition of TIGT and TMID in 2012 and have adjusted the provisional amounts during 2013 for certain immaterial items related to regulatory assets and accrued liabilities assumed in the acquisition. Of the $304.5 million of goodwill at December 31, 2013, $225.3 million was assigned to the Gas Transportation and Storage segment and $79.2 million was assigned to the Processing segment. For more information regarding our segments, see Note 16 *Reporting Segments*.

TEP evaluates goodwill for impairment on an annual basis during the third quarter and whenever events or changes in circumstances necessitate an evaluation for impairment. Examples of such facts and circumstances include the excess of fair value over carrying amount in the last valuation or changes in business environment. TEP evaluates goodwill impairment by reporting unit level, which is an operating segment as defined in the segment reporting guidance of the Codification, using either the qualitative assessment option or the two-step test approach depending on facts and circumstances of the reporting unit. Our reporting units are the same as our reporting segments. If TEP, after performing the qualitative assessment, determines it is more likely than not that the fair value of a reporting unit is greater than its carrying amount, the two-step impairment test is unnecessary. When goodwill is evaluated for impairment using the two-step test, the carrying amount of the reporting unit is compared to its fair value in Step 1 and if the fair value exceeds the carrying amount, Step 2 is unnecessary. If the carrying amount exceeds the reporting unit s fair value, this could indicate potential impairment and Step 2 of the goodwill evaluation process is required to determine if goodwill is impaired and to measure the amount of impairment loss to recognize, if any. When Step 2 is necessary, the fair value of individual assets and liabilities is determined using valuations, or other observable sources of fair value, as appropriate. If the carrying amount of goodwill exceeds its implied fair value, the excess is recognized as an impairment loss.

TEP did not elect to apply the qualitative assessment option during our 2013 annual goodwill impairment testing, instead we proceeded directly to the two-step quantitative test. In Step 1 of the two-step quantitative test, we compared the fair value of each reporting unit with its respective book value, including goodwill, by using an income approach based on a discounted cash flow analysis. For the purposes of goodwill impairment testing, goodwill was allocated to our reporting units based on the enterprise value of each reporting unit at the date of acquisition. The fair value of each reporting unit was determined on a stand-alone basis from the perspective of a market participant and included a sensitivity analysis of the impact of changes in various assumptions. This approach required us to make long-term forecasts of future operating results and various other assumptions and estimates, the most significant of which are gross margin, operating expenses, general and administrative expenses, long-term growth rates and the weighted average cost of capital. The fair value of the reporting units was determined using significant unobservable inputs, considered Level 3 under the fair value hierarchy in the Codification. For each reporting unit, the results of the Step 1 impairment analysis indicated no potential impairment as the fair value of the reporting units was substantially greater than their respective book values. As a result, in accordance with the Codification guidance, Step 2 of the impairment analysis was not necessary as part of the annual impairment analysis in 2013. Unpredictable events or deteriorating market or operating conditions could result in a future change to the discounted cash flow models and cause impairments in the future. We continue to monitor potential impairment indicators to determine if a triggering event occurs and will perform additional goodwill impairment analyses as necessary.

Investment in Unconsolidated Affiliates

We use the equity method to account for investments in greater than 20% owned affiliates that are not variable interest entities and where we do not have the ability to exercise control, and for investments in less than 20% owned affiliates where we have the ability to exercise significant influence.

We evaluate our investments in unconsolidated affiliates for impairment whenever events or changes in circumstances indicate that the carrying value of such investments may have experienced a decline in value. When there is evidence of loss in value, we compare the estimated fair value of the investment to the carrying value of the investment to determine whether impairment has occurred. We assess the fair value of our investments in unconsolidated affiliates using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. The difference between the carrying amount of the unconsolidated affiliates and their estimated fair value is recognized as an impairment loss when the loss in value is deemed to be other-than-temporary.

TEP s investment in Grasslands Water Services, Inc. (GWSI), which owns a water transportation pipeline, is recorded under the equity method of accounting as TEP has the ability to exercise significant influence, but not control, over this investment. The investment is reported within the line item Deferred charges and other assets on the consolidated balance sheet. As of December 31, 2013, the carrying amount of TEP s investment in GWSI of $1.3 million consisted of cash contributions made during the year ended December 31, 2013. There was no equity in earnings recognized for the year ended December 31, 2013.

Revenue Recognition

TEP and TEP Pre-Predecessor recognize revenues as services are rendered or goods are sold to a purchaser at a fixed and determinable price, delivery has occurred, title has transferred and collectability is reasonably assured. TEP and TEP Pre-Predecessor provide various types of natural gas storage and transportation services to their customers in which the natural gas remains the property of these customers at all times.

Natural gas liquids sales occur in the Processing segment and consist of the sale of outputs from our processing plants and the marketing of natural gas liquids that are purchased from our suppliers.

Natural gas sales occur in both the Gas Transportation and Storage segment and in the Processing segment. In the Gas Transportation and Storage segment, transportation services revenue is recognized when a portion of the natural gas transported by customers is collected as a contractual fee to compensate TEP and TEP Pre-Predecessor for fuel consumed by pipeline and storage operations. We take title and record revenue at market prices when the volumes included in the contractual fee are delivered from the customer and injected into our storage facility. When the excess volumes are eventually sold we record natural gas sales revenue at the contractual sales price and cost of sales and transportation services at average cost. In addition, when operational conditions allow, TEP and TEP Pre-Predecessor occasionally sell cushion gas, which refers to the minimum volume of natural gas required in order to operate the storage facility. In the Processing segment, we purchase natural gas primarily for use in our operations and for meeting contractual requirements to deliver natural gas to certain customers. In addition, some of our contractual arrangements allow us to keep a portion of the processed natural gas as compensation for processing services. We generate revenue by selling the volumes of natural gas received or purchased that exceed our business needs.

Transportation services occur in the Gas Transportation and Storage segment. In many cases (generally described as firm service), the customer pays a two-part rate that includes (i) a fee reserving the right to transport or store natural gas in TEP and TEP Pre-Predecessors facilities and (ii) a per-unit rate for volumes actually transported or injected into/withdrawn from storage. The fee-based component of the overall rate is recognized as revenue in the period the service is provided. The per-unit charge is recognized as revenue when the volumes are delivered to the customers agreed upon delivery point, or when the volumes are injected into/withdrawn from TEP and TEP Pre-Predecessors storage facilities. In other cases (generally described as interruptible service), there is no fee associated with the services because the customer accepts the possibility that service may be interrupted at TEP and TEP Pre-Predecessors discretion in order to serve customers who have purchased firm service. In the case of interruptible service, revenue is recognized in the same manner utilized for the per-unit rate for volumes actually transported under firm service agreements. In addition to firm and interruptible transportation services, TEP and TEP Pre-Predecessor also provide natural gas park and loan services to assist customers in managing short-term gas surpluses or deficits. Revenues are recognized as services are provided, based on the terms negotiated under these contracts.

Processing and other revenues primarily represent processing fees earned in the Processing segment.

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Commitments and Contingencies

We recognize liabilities for other commitments and contingencies when, after fully analyzing the available information, we determine it is probable that a liability has been incurred and the amount of loss can be reasonably estimated. When a range of probable loss can be estimated, we accrue the most likely amount, or if no amount is more likely than another, we accrue the minimum of the range of probable loss.

Environmental Costs

TEP and TEP Pre-Predecessor expense or capitalize, as appropriate, environmental expenditures that relate to current operations. TEP and TEP Pre-Predecessors expense amounts that relate to an existing condition caused by past operations that do not contribute to current or future revenue generation. TEP and TEP Pre-Predecessor do not discount environmental liabilities to a net present value, and record environmental liabilities when environmental assessments and/or remedial efforts are probable and costs can be reasonably estimated. Recording of these accruals coincides with the completion of a feasibility study or a commitment to a formal plan of action. Estimates of environmental liabilities are based on currently available facts and presently enacted laws and regulations taking into consideration the likely effects of other factors including our prior experience in remediating contaminated sites, other companies clean-up experience and data released by government organizations. Our estimates are subject to revision in future periods based on actual cost or new information.

Fair Value

Fair value, as defined in the Codification, is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, or exit price. TEP and TEP Pre-Predecessor apply the fair value measurement guidance to financial assets and liabilities in determining the fair value of derivative assets and liabilities, and to nonfinancial assets and liabilities upon the acquisition of a business or in conjunction with the measurement of an impairment loss on an asset group or goodwill under the accounting guidance for the impairment of long-lived assets or goodwill.

The fair value measurement accounting guidance requires that TEP and TEP Pre-Predecessor make assumptions that market participants would use in pricing an asset or liability based on the best information available. These factors include nonperformance risk (the risk that the obligation will not be fulfilled) and credit risk of the reporting entity (for liabilities) and of the counterparty (for assets). The fair value measurement guidance prohibits the inclusion of transaction costs and any adjustments for blockage factors in determining the instruments fair value. The principal or most advantageous market should be considered from the perspective of the reporting entity.

Fair value, where available, is based on observable market prices. Where observable market prices or inputs are not available, different valuation models and techniques are applied. These models and techniques attempt to maximize the use of observable inputs and minimize the use of unobservable inputs. The process involves varying levels of management judgment, the degree of which is dependent on the price transparency of the instruments or market and the instruments complexity.

To increase consistency and enhance disclosure of fair value, the Codification creates a fair value hierarchy to prioritize the inputs used to measure fair value into three categories. An asset or liability s level within the fair value hierarchy is based on the lowest level of input significant to the fair value measurement, where Level 1 is the highest and Level 3 is the lowest. The three levels are defined as follows:

Level 1 Inputs quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date;

Level 2 Inputs inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability; and

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Level 3 Inputs unobservable inputs for the asset or liability. These unobservable inputs reflect the entity s own assumptions about the assumptions that market participants would use in pricing the asset or liability, and are developed based on the best information available in the circumstances (which might include the reporting entity s own data).

Any transfers between levels within the fair value hierarchy are recognized at the end of the reporting period.

For information regarding financial instruments measured at fair value on a recurring basis, see Note 7 *Risk Management*. For information regarding the fair value of financial instruments not measured at fair value in the Consolidated Balance Sheets, see Note 8 *Long-term Debt*.

Risk Management Activities

TEP and TEP Pre-Predecessor utilize energy derivatives for the purpose of mitigating its risk resulting from fluctuations in the market price of natural gas and associated transportation. TEP and TEP Pre-Predecessor record derivative contracts at their estimated fair values as of each reporting date. TEP Pre-Predecessor designated certain derivative instruments as qualifying hedges. TEP has elected not to apply hedge accounting for these derivative instruments. For more information on TEP and TEP Pre-Predecessors risk management activities, see Note 7 *Risk Management*.

Equity-Based Compensation

Equity-based compensation grants are measured at their grant date fair value and related compensation cost is recognized over the vesting period of the grant. Compensation cost for awards with graded vesting provisions is recognized on a straight-line basis over the requisite service period of each separately vesting portion of the award. As discussed in Note 13 *Equity-Based Compensation*, a portion of the expense recognized relating to equity-based compensation grants is charged to TD.

Income Taxes

TEP and TEP Pre-Predecessor are comprised of limited liability companies that have elected to be treated as partnerships for income tax purposes. Accordingly, no provision for federal or state income taxes has been recorded in the financial statements of TEP and TEP Pre-Predecessor and the tax effects of TEP and TEP Pre-Predecessors activities accrue to their parents. TEP Pre-Predecessor historically incurred Texas Margin Taxes because it was a part of an affiliated group that generated sales in the State of Texas. Subsequent to the acquisition of TEP Pre-Predecessor by Tallgrass in November 2012, TEP is no longer a part of an affiliated group with sales in Texas and therefore will no longer be subject to Texas Margin Taxes or any other income-based taxes based on currently enacted tax legislation.

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 ASU No. 2011-11 applies to derivatives accounted for in accordance with the Codification guidance for

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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 TEP s financial statements.

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. The adoption of ASU 2013-02 did not have a material impact on TEP s financial statements.

3. Business Combinations

On November 13, 2012, TD completed the acquisition of certain assets from TEP Pre-Predecessor Parent for approximately \$1.8 billion in cash and approximately \$1.5 billion of assumed debt. The acquisition included 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 all of the net assets, \$573.2 million was allocated to TIGT and TMID. The contribution of the assets and liabilities of TIGT and TMID from TD to TEP, which was effective on May 17, 2013, was accounted for as a transaction between entities under common control under ASC 805.

The following table represents the fair value of assets and liabilities of TIGT and TMID, as acquired by TD on November 13, 2012. The fair value is based on TD s allocation of the purchase price for TIGT and TMID to the assets acquired and liabilities assumed:

	Preliminary	Adjustments (in thousands)	Final
Cash	$ 1,982	$	$ 1,982
Accounts receivable and gas imbalances	29,821	(1,670)	28,151
Inventories	2,306		2,306
Other current assets	382	(294)	88
Property, plant and equipment	655,722		655,722
Other noncurrent assets	37,334	(1,986)	35,348
Accounts payable, accrued liabilities and gas imbalances	(34,137)	2,428	(31,709)
Current portion of long-term debt	(4,000)		(4,000)
Other current liabilities	(26,113)		(26,113)
Long-term debt	(390,373)		(390,373)

Other long-term liabilities and deferred credits	(1,534)	(1,100)	(2,634)
Net identifiable assets acquired	271,390	(2,622)	268,768
Goodwill	301,852	2,622	304,474
Net assets acquired	$ 573,242	$	$ 573,242

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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. During the year ended December 31, 2013, the preliminary purchase price allocation was adjusted with respect to TIGT and TMID for certain immaterial items related to regulatory assets and accrued liabilities. These changes were not considered material to TEP, so the adjustments are not retrospectively reflected in the accompanying consolidated balance sheet as of December 31, 2012.

The regulation of natural gas pipelines is an integral attribute of the assets contributed by TD and therefore was included in the determination of the fair value of the regulated assets. The Pre-Predecessor s net book value of natural gas pipeline assets was higher than the historical regulatory net book value, and a comparative decrease in the gross book value of the natural gas pipelines resulted from adjusting the regulatory assets to their approximate fair value. The new basis of property, plant and equipment at December 31, 2012 represents the fair value on November 13, 2012 of the assets contributed to us by TD plus capital expenditures made through December 31, 2012. The fair value on November 13, 2012 of the regulated assets contributed to us by TD in connection with the IPO approximated the net book value of those assets on a regulated basis. The fair value of the non-regulated assets contributed to us by TD in connection with the IPO approximated their replacement cost values on November 13, 2012 and reflect a higher fair market value as compared to the Pre-Predecessor s basis.

Prior to May 17, 2013, the long-term debt held by TD was guaranteed by TIGT and TMID, and $400 million of that debt was expected to be assumed by TEP concurrently with the IPO, and was therefore allocated to TIGT and TMID along with the related deferred financing costs at November 13, 2012. On May 17, 2013, concurrently with the closing of the IPO, this $400 million 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 8 *Long-term Debt*.

The goodwill recorded in the consolidated balance sheet is expected to be deductible for tax purposes. 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 is presented as if the acquisition of TIGT and TMID had been completed on January 1, 2011. The pro forma financial information is not necessarily indicative of what the actual results of operations or financial position of TEP 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 TEP Pre-Predecessor 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 Pre-Predecessor	
	Period from January 1 to November 12, 2012	Year Ended December 31, 2011

	(in thousands)	
Revenue	$ 220,292	$ 307,043
Net income	$ 25,890	$ 48,036

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Pro forma revenue contains no adjustments to the historical amounts. Pro forma net income includes adjustments for the period from January 1, 2012 to November 12, 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 that resulted from the allocation of the purchase price to the fair value of the assets and liabilities acquired by TD.

(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

TEP has no employees. TEP Pre-Predecessor Parent 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 similarly provided and charged TEP for direct and indirect costs of services. TEP and TEP Pre-Predecessor record these costs on the accrual basis in the period in which TEP Pre-Predecessor Parent (or TD, beginning November 13, 2012) incurs them. Each of the wholly-owned companies comprising TEP and TEP Pre-Predecessor had agency arrangements with TEP Pre-Predecessor Parent or its affiliates (prior to November 13, 2012) and TD (beginning November 13, 2012) under which TEP Pre-Predecessor Parent, or its contractually obligated affiliate, or TD, as applicable, pay costs and expenses incurred by TEP and TEP Pre-Predecessor, act as agents for TEP and TEP Pre-Predecessor, and are reimbursed by TEP and TEP Pre-Predecessor 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 TEP Pre-Predecessor Parent to TD.

On May 17, 2013, in connection with the closing of the IPO, 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 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.

Effective May 17, 2013, TEP also pays a quarterly reimbursement to TD for costs associated with being a public company. The public company reimbursement amount was $625,000 per quarter in 2013. These reimbursement amounts will be periodically reviewed and adjusted as necessary to continue to reflect reasonable allocation of costs to TEP.

Due to the cash management agreements discussed in Note 2 *Summary of Significant Accounting Policies*, intercompany balances were periodically settled and treated as equity distributions prior to the completion of the IPO on May 17, 2013.

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Totals of transactions with affiliated companies are as follows:

	TEP		TEP Pre-Predecessor	
	Year Ended December 31, 2013	Period from November 13 to December 31, 2012	Period from January 1 to November 12, 2012	Year Ended December 31, 2011
	(in thousands)		(in thousands)	
Cost of sales and transportation services	$ 131	$ 23	$ 155	$ 182
Charges to TEP and TEP Pre-Predecessor: [(1)]				
Property, plant and equipment, net	$ 6,916	$ 190	$ 1,052	$ 1,248
Other deferred charges	$ 1,100	$ 56	$ 130	$ 75
Operation and maintenance	$ 16,273	$ 2,551	$ 12,874	$ 16,016
General and administrative	$ 14,866[(2)]	$ 5,478	$ 7,960	$ 13,156
Property, plant and equipment purchases from:				
KMP	$	$	$	$ 1
Property, plant and equipment sales to:				
Tallgrass Development, LP	$ 82,990[(3)]	$	$	$
KMP	$	$	$ 1,948	$
NGPL PipeCo LLC	$	$	$	$ 4

(1) Charges to TEP and TEP Pre-Predecessor include directly charged wages and salaries, other compensation and benefits, and shared services.

(2) During the year ended December 31, 2013, TEP reimbursed TD for general and administrative expenses pursuant to the Omnibus Agreement discussed above, resulting in allocated amounts for general and administrative costs rather than individual charges as in prior periods.

(3) Property, plant and equipment sold to TD during the year ended December 31, 2013 consists of the Pony Express Assets, as discussed in Note 6 *Property, Plant and Equipment*.

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

	December 31, 2013	December 31, 2012
	(in thousands)	
Accounts receivable from affiliated companies:		
Tallgrass Operations, LLC	$	$ 6,244
Rockies Express Pipeline LLC		219

Total accounts receivable from affiliated companies	$		$	6,463
Payables to affiliated companies:				
Note payable to TD	$		$	1,381
Interest payable to TD				6
Accounts payable to Tallgrass Operations, LLC		7,106		
Accounts payable to Rockies Express Pipeline LLC		28		
Total payables to affiliated companies	$	7,134	$	1,387

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Balances of gas imbalances with affiliated shippers are as follows:

	December 31, 2013	December 31, 2012
	(in thousands)	
Affiliate gas balance receivables	$ 7	$
Affiliate gas balance payable	$ 116	$ 276

Pursuant to the terms of a Purchase and Sale Agreement dated August 1, 2012, TD, on behalf of its wholly-owned subsidiary, Tallgrass Pony Express, LLC (PXP), is reimbursing TIGT for all costs TIGT incurs with respect to the Pony Express Abandonment, as defined in Note 14 *Regulatory Matters*, inclusive of development costs, capital costs and related interest costs associated with securing regulatory approvals for the construction of certain gas facilities necessary to maintain existing natural gas service on the TIGT system (the Replacement Gas Facilities). The Replacement Gas Facilities are required as part of the Pony Express Abandonment and are required in order for TIGT to continue existing service to customers after the Pony Express Assets, as discussed in Note 6 *Property, Plant and Equipment*, are sold to PXP. Expenditures are being captured in Prepayments and other current assets on the Consolidated Balance Sheet as they are incurred and interest is accrued until reimbursement takes place which is usually monthly. At December 31, 2013, TEP had $17.0 million in Prepayments and other current assets related to this project. During the year ended December 31, 2013, reimbursements of $4.3 million related to expenditures prior to the closing of the IPO on May 17, 2013 were settled as equity distributions with TD. During the year ended December 31, 2013, reimbursements of $30.4 million related to expenditures subsequent to the closing of the IPO on May 17, 2013 were cash settled by TD.

5. Inventory

The components of inventory consisted of the following:

	TEP	
	December 31, 2013	December 31, 2012
	(in thousands)	
Materials and supplies	$ 1,736	$ 1,567
Natural gas liquids	1,009	637
Gas in underground storage	2,403	
Total inventory	$ 5,148	$ 2,204

6. Property, Plant and Equipment

A summary of net property, plant and equipment by classification is as follows:

	December 31, 2013	December 31, 2012
	(in thousands)	

Natural gas pipelines	$ 339,430	$ 421,644
Processing and treating assets	209,329	195,108
Buildings	15,479	15,518
Vehicles	3,210	3,138
Gas in underground storage	2,141	2,345
Land	1,526	1,534
General and other	2,503	1,207
Construction work in progress	39,369	32,932
Accumulated depreciation and amortization	(18,076)	(3,950)
Total property, plant and equipment, net	$ 594,911	$ 669,476

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As discussed further in Note 14 *Regulatory Matters*, during the fourth quarter of 2013 TIGT closed the sale of approximately 430 miles of natural gas pipeline, rights-of-way and related equipment and assets, referred to as the Pony Express Assets, to a subsidiary of TD. The net book value of the assets at the date of transfer was approximately $83.0 million. There was no gain or loss recognized on the sale.

Capitalized interest was approximately $752,000 for the year ended December 31, 2013, $9,000 for the period from November 13, 2012 to December 31, 2012, $15,000 for the period from January 1, 2012 to November 12, 2012 and $34,000 for the year ended December, 31 2011.

Under a lease agreement effective November 13, 2012, TIGT, as lessor, leases a portion of its office space to a third party. Rental income for the year ended December 31, 2013 and the period from November 13, 2012 to December 31, 2012 was approximately $1.0 million and $145,000, respectively, and was recorded as other income in the accompanying Consolidated Statements of Income. As of December 31, 2013, future minimum rental income under non-cancelable operating leases as the lessor were as follows (in thousands):

Year	Total
2014	$ 1,031
2015	258
2016	
2017	
2018	
Thereafter	
Total	$ 1,289

7. Risk Management

TEP and TEP Pre-Predecessor enter into derivative contracts with third parties for the purpose of hedging exposures that accompany their normal business activities. TEP and TEP Pre-Predecessor s normal business activities expose them 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 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 period January 1, 2012 to November 12, 2012, the 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, the TEP Pre-Predecessor also reclassified the associated gains and losses included in accumulated other comprehensive income into earnings. During the period January 1, 2012 to November 12, 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.

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Fair Value of Derivative Contracts

The following table summarizes the fair values of TEP s derivative contracts included in the accompanying Consolidated Balance Sheets:

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

	Balance Sheet Location	December 31, 2013	December 31, 2012
		(in thousands)	
Energy commodity derivative contracts	Current liabilities	$ 184	$ 23
Total derivative liabilities		$ 184	$ 23

As of December 31, 2013, the fair value shown for commodity contracts was comprised of derivative volumes totaling 0.8 Bcf of fixed-price swaps.

Effect of Derivative Contracts on the Income Statement

The following tables summarize the impact of derivative contracts for the years ended December 31, 2013, the periods from November 13, 2012 to December 31, 2012 and January 1, 2012 to November 12, 2012, and the year ended 2011:

	Amount of gain/(loss) recognized in OCI on derivatives (effective portion)			
	TEP		TEP Pre-Predecessor	
	Year Ended December 31, 2013	Period from November 13 to December 31, 2012	Period from January 1 to November 12, 2012	Year Ended December 31, 2011
	(in thousands)		(in thousands)	
Derivatives in cash flow hedging relationships:				
Energy commodity derivative contracts	$	$	$ 1,024	$ 6,146

Amount of gain/(loss) reclassified from Accumulated OCI into income (effective por

	Location of gain/ (loss) reclassified from AOCI into income (effective portion)	TEP		TEP Pre-Predecessor	
		Year Ended December 31, 2013	Period from November 13 to December 31, 2012	Period from January 1 to November 12, 2012	Year Ended December 31, 2011
		(in thousands)		(in thousands)	
Derivatives in cash flow hedging relationships:					
Energy commodity derivative contracts	Natural gas sales	$	$	$ 4,187	$ 3,410

	Location of gain/ (loss) recognized in income on derivative	Amount of gain/(loss) recognized in income on derivatives			
		TEP		TEP Pre-Predecessor	
		Year Ended December 31, 2013	Period from November 13 to December 31, 2012	Period from January 1 to November 12, 2012	Year Ended December 31, 2011
		(in thousands)		(in thousands)	
Derivatives not designated as hedging contracts:					
Energy commodity derivative contracts	Natural gas sales	$ (548)	$ 416	$	$

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Credit Risk

TEP has counterparty credit risk as a result of its use of financial derivative contracts. TEP s counterparties consist of major financial institutions. This concentration of counterparties may impact TEP s 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.

TEP maintains credit policies 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, TEP s management does not anticipate a material adverse effect on our financial position, results of operations, or cash flows as a result of counterparty performance.

TEP s 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 a financial institution with an investment grade credit rating. While TEP enters 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 December 31, 2013, the fair value of TEP s derivative contracts was a liability, resulting in no credit exposure from our counterparty as of that date.

In addition, when the market value of TEP s derivative contracts with specific counterparties exceeds established limits, TEP is required to provide collateral to its counterparties, which may include posting letters of credit or placing cash in margin accounts. As of December 31, 2013 and 2012, TEP did not have any outstanding letters of credit or cash in margin accounts in support of its hedging of commodity price risks associated with the sale of natural gas. As of December 31, 2013 and 2012, TEP had no margin deposits with counterparties associated with energy commodity contract positions.

Fair Value

Derivative assets and liabilities are measured and reported at fair value. Derivative contracts can be exchange-traded or traded 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. TEP values 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. TEP uses 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 TEP s 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.

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The following tables summarize the fair value measurements of TEP s energy commodity derivative contracts as of December 31, 2013 and 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 as of December 31, 2013				
Energy commodity derivative contracts	$	$	$	$
TEP as of December 31, 2012				
Energy commodity derivative contracts	$ 224	$	$ 224	$

	Liability 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 as of December 31, 2013				
Energy commodity derivative contracts	$ 184	$	$ 184	$
TEP as of December 31, 2012				
Energy commodity derivative contracts	$ 23	$	$ 23	$

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

	TEP		TEP Pre-Predecessor	
	Year Ended December 31, 2013	Period from November 13 to December 31, 2012	Period from January 1 to November 12, 2012	Year Ended December 31, 2011
	(in thousands)		(in thousands)	
Derivatives net asset (liability):				
Beginning of period	$	$	$ (352)	$ (124)
Total gains or (losses)				

Included in other comprehensive income			(61)	(1,099)
Settlements			156	871
Transfers out of Level 3			257	
End of period	$	$	$	$ (352)
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	$	$	$	$

During the period from January 1, 2012 to November 12, 2012, derivative liabilities with a fair value of $257,000 were transferred from Level 3 to Level 2 as the level of observable inputs used to value those instruments was deemed to be significant.

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8. Long-term Debt

TEP s long-term debt consisted of the following at December 31, 2013 and 2012:

	December 31, 2013	December 31, 2012
	(in thousands)	
Borrowings under revolving credit facility	$ 135,000	$
Term loan due 2018 (allocated from TD)		400,000
Unamortized discount		(5,509)
Total principal	135,000	394,491
Current maturities		(4,000)
Total long-term debt	$ 135,000	$ 390,491

Revolving Credit Facility

On May 17, 2013, in connection with the IPO, TEP entered into a $500 million senior secured revolving credit facility with Barclays Bank PLC, as administrative agent, and a syndicate of lenders (the revolving credit facility), which will mature on May 17, 2018. On the closing date of the IPO, TEP borrowed $231.0 million under the credit facility, the proceeds of which were used to (i) repay the approximately $104.1 million of debt assumed from TD that remained after payment of a portion of the assumed debt with proceeds from the IPO; (ii) pay a distribution to TD of $31.2 million equal to the net proceeds from the exercise of the underwriter s overallotment option to purchase additional common units; (iii) pay $85.5 million to TD as reimbursement for a portion of the capital expenditures made by TD to purchase the contributed assets and (iv) pay origination fees related to the new revolving credit facility and certain other fees associated with the IPO, and fund working capital requirements of TEP. The remaining commitments under the credit facility are available to provide for capital expenditures, permitted acquisitions, working capital needs 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. As of December 31, 2013, TEP had outstanding borrowings of $135.0 million and had issued letters of credit totaling $654,000. As of December 31, 2013, TEP had available borrowing capacity under the revolving credit facility of $364.3 million.

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. In addition, 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 are required. As of December 31, 2013, TEP is in compliance with the covenants required under the revolving credit facility.

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% or (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 was initially 1.00%, and for loans bearing interest based on the reserve adjusted Eurodollar rate, the applicable margin was initially 2.00%. After September 30, 2013, the applicable margin will range from 1.00% to 2.00% for base rate borrowings and from 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 was initially 0.375%, and after September 30, 2013, is either 0.375% or 0.500%, based on TEP s total leverage ratio. As of December 31, 2013, the weighted average interest rate on outstanding borrowings was 2.52%.

Long-term Debt Allocated from TD

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 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 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 IPO on May 17, 2013, TEP legally assumed the previously allocated $400 million portion of the TD term loan and used a portion of the IPO 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. TEP recognized a loss on extinguishment of debt of $17.5 million during year ended December 31, 2013 associated with the portion of deferred financing costs and unamortized discount on the amount of the TD term loan that was allocated to TEP.

Fair Value

The following table sets forth the carrying amount and fair value of TEP s long-term debt, which is not measured at fair value in the Consolidated Balance Sheets as of December 31, 2013 and 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)				
December 31, 2013	$	$ 135,000	$	$ 135,000	$ 135,000
December 31, 2012	$	$ 404,000	$	$ 404,000	$ 394,491

The long-term debt borrowed under the revolving credit facility and the term loan allocated from TD were carried at amortized cost. As of December 31, 2013, the fair value approximates the carrying amount for the borrowings under the revolving credit facility using a discounted cash flow analysis. The fair value of the debt allocated from TD at December 31, 2012 was estimated based on quoted market prices. TEP is not aware of any factors that would significantly affect the estimated fair value since December 31, 2013.

9. Commitments and Contingent Liabilities

Leases

Rent expense under operating leases and right of way agreements totaled approximately $278,000, $37,000, $206,000 and $248,000 for the year ended 2013, the periods from November 13, 2012 to December 31, 2012 and January 1, 2012 to November 12, 2012 and the year ended 2011, respectively.

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At December 31, 2013, future minimum rental commitments under major non-cancelable operating leases were as follows (in thousands):

Year	Total
2014	363
2015	378
2016	317
2017	256
2018	143
Thereafter	553
Total	$ 2,010

Capital Expenditures

Approximately $1.9 million had been committed for the future purchase of property, plant and equipment at December 31, 2013. An additional $23.4 million had been committed for future capital expenditures related to the Pony Express Abandonment project at December 31, 2013. These expenditures will be reimbursed by PXP. For additional information, see Note 14 *Regulatory Matters*.

10. Partnership Equity and Distributions

As discussed in Note 1 *Description of Business*, TD completed the acquisition of TEP Pre-Predecessor subsidiary entities on November 13, 2012. On May 17, 2013, in conjunction with the closing of TEP s IPO, TD s ownership interest in TIGT and TMID was contributed to TEP in exchange for 9,700,000 common and 16,200,000 subordinated units (and other consideration consisting of debt assumption and cash distribution as more fully described above in Note 1 *Description of Business*.)

Distributions to Holders of Common Units, Subordinated Units and General Partner Units

TEP s partnership agreement requires TEP to distribute its available cash, defined below, to unitholders of record on the applicable record date within 45 days after the end of each quarter, beginning with the quarter ended June 30, 2013. TEP s partnership agreement provides that available cash, each quarter, is first distributed to the common unitholders and the general partner on a pro rata basis until each common unitholder has received $0.2875 per unit, which amount is defined in TEP s partnership agreement as the minimum quarterly distribution (MQD). During the subordination period, defined below, holders of the subordinated units are not entitled to receive a distribution of available cash until each holder of common units has received the MQD, and if the MQD is not paid for any quarter, the cumulative amount of any arrearages in the payment of the MQD from prior quarters.

The following table shows the distributions for the year ended December 31, 2013:

		Distributions	
	Limited Partners	**General**	**Distributions**
	Common	**Partner**	**per**

Three Months Ended	Date Paid	and Subordinated	Incentive	2%	Total	Limited Partner Unit
		(in thousands, except per unit amounts)				
December 31, 2013	February 12, 2014	$ 12,757	$ 63	$ 262	$ 13,082	$ 0.3150
September 30, 2013	November 13, 2013	12,049		245	12,294	0.2975
June 30, 2013 (1)	August 13, 2013	5,759		118	5,877	0.1422(1)

(1) The distribution declared on July 18, 2013 for the second quarter of 2013 represented a prorated amount of TEP s MQD of $0.2875 per common unit, based upon the number of days between the closing of the IPO on May 17, 2013 to June 30, 2013.

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Subordinated Units

All subordinated units are currently held by TD. The principal difference between our common units and subordinated units is that in any quarter during the subordination period, holders of the subordinated units are not entitled to receive a distribution of available cash until the holders of common units have received the MQD (inclusive of any cumulative arrearages of previously unpaid MQD from previous quarters). Furthermore, subordinated unitholders are not entitled to receive arrearages in previous quarter distributions. The practical effect of the subordinated units is to increase the likelihood that during the subordination period there will be available cash to be distributed on the common units. The subordination period will end, and the subordinated units will convert to common units, on a one-for-one basis, when certain distribution milestones described in the partnership agreement have been met.

Incentive Distribution Rights

The GP owns a 2% general partner interest in TEP which is represented by 826,531 general partner units. The GP also owns all of the incentive distribution rights (IDRs). IDRs represent the right to receive an increasing percentage (13%, 23% and 48%) of quarterly distributions of available cash from operating surplus after the MQD and the target distribution levels have been achieved. The GP may transfer these rights separately from its general partner interest, subject to restrictions in our partnership agreement. Under TEP s partnership agreement, the general partner may at any time contribute additional capital to TEP in order to maintain its 2% general partner interest.

The following discussion related to incentive distributions assumes that TEP s general partner maintains its 2.0% general partner interest and continues to own all of the IDRs.

If for any quarter:

TEP has distributed available cash from operating surplus to all of the common unitholders (and during the subordination period, to the subordinated unitholders) in an amount equal to the MQD for each outstanding unit for such quarter; and

TEP has distributed available cash from operating surplus on outstanding common units in an amount necessary to eliminate any cumulative arrearages in payment of the MQD to common unitholders;

then, TEP will distribute additional available cash from operating surplus for that quarter among the unitholders and the GP in the following manner:

first, 98% to all unitholders, pro rata, and 2% to TEP s general partner, until each unitholder receives a total of $0.3048 per unit for that quarter (the first target distribution);

second, 85% to all unitholders, pro rata, and 15% to TEP s general partner, until each unitholder receives a total of $0.3536 per unit for that quarter (the second target distribution);

third, 75% to all unitholders, pro rata, and 25% to TEP s general partner, until each unitholder receives a total of $0.4313 per unit for that quarter (the third target distribution); and

thereafter, 50% to all unitholders, pro rata, and 50% to TEP s general partner.

Definition of Available Cash

Available cash generally means, for any quarter, all cash and cash equivalents on hand at the end of that quarter:

less, the amount of cash reserves established by TEP s general partner to:

provide for the proper conduct of our business (including reserves for our future capital expenditures, for anticipated future credit needs subsequent to that quarter, for legal matters and for refunds of collected rates reasonably likely to be refunded as a result of a settlement or hearing related to FERC rate proceedings);

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comply with applicable law or regulation, any of TEP s debt instruments or other agreements; or

provide funds for distributions to unitholders and to TEP s general partner for any one or more of the next four quarters (provided that TEP s general partner may not establish cash reserves for distributions if the effect of the establishment of such reserves will prevent TEP from distributing the MQD on all common units and any cumulative arrearages on such common units for the current quarter);

plus, if TEP s general partner so determines, all or any portion of the cash on hand on the date of distribution of available cash for the quarter, including cash on hand resulting from working capital borrowings made subsequent to the end of such quarter.

Distributions to TD

As discussed in Note 2 *Summary of Significant Accounting Policies*, prior to May 17, 2013, 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*, was recognized as equity distributions during that time period. Excluding the cash distributions paid to TD as a common and subordinated unitholder, as discussed above, there were net distributions from TEP to TD for the year ended December 31, 2013 of $118.5 million, which included the $85.5 million to TD related to the contribution of TIGT and TMID to TEP as well as the $31.2 million net proceeds from the exercise of the underwriter s option to purchase additional common units as part of the IPO. There were no net distributions from TEP to TD for the period from November 13, 2012 to December 31, 2012. Net distributions from TEP Pre-Predecessor to its parent for the period from January 1, 2012 to November 12, 2012 were $57.7 million.

11. Net Income per Limited Partner Unit

The Partnership s net income is allocated to the general partner and the limited partners, including the holders of the subordinated units, in accordance with their respective ownership percentages, after giving effect to incentive distributions paid to the general partner. Basic and diluted net income per limited partner unit is calculated by dividing limited partners interest in net income, less general partner incentive distributions, by the weighted average number of outstanding limited partner units during the period.

We compute earnings per unit using the two-class method for Master Limited Partnerships as prescribed in the FASB guidance. The two-class method requires that securities that meet the definition of a participating security be considered for inclusion in the computation of basic earnings per unit. Under the two-class method, earnings per unit is calculated as if all of the earnings for the period were distributed under the terms of the partnership agreement, regardless of whether the general partner has discretion over the amount of distributions to be made in any particular period, whether those earnings would actually be distributed during a particular period from an economic or practical perspective, or whether the general partner has other legal or contractual limitations on its ability to pay distributions that would prevent it from distributing all of the earnings for a particular period.

We calculate net income available to limited partners based on the distributions pertaining to the current period s net income. After adjusting for the appropriate period s distributions, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to the general partner and limited partners in accordance with the contractual terms of the partnership agreement and as further prescribed in the FASB guidance under the two-class method.

The two-class method does not impact our overall net income or other financial results; however, in periods in which aggregate net income exceeds our aggregate distributions for such period, it will have the impact of reducing net income per limited partner unit. This result occurs as a larger portion of our aggregate earnings, as if distributed, is allocated to the incentive distribution rights of the general partner, even though we make

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distributions on the basis of available cash and not earnings. In periods in which our aggregate net income does not exceed our aggregate distributions for such period, the two-class method does not have any impact on our calculation of earnings per limited partner unit.

Basic earnings per unit is computed by dividing net earnings attributable to unitholders by the weighted average number of units outstanding during each period. However, because our IPO was completed on May 17, 2013, the number of units issued following the IPO is utilized for the 2013 periods presented. Diluted earnings per unit reflects the potential dilution of common equivalent units that could occur if equity participation units are converted into common units.

As the IPO was completed on May 17, 2013, no income from the period from January 1, 2013 to May 16, 2013 is allocated to the limited partner units that were issued on May 17, 2013 and all income for such period was allocated to the general partner. Net income per limited partner unit is only calculated for the year ended December 31, 2013 as no units were outstanding during the same periods in 2012.

The following table illustrates the Partnership s calculation of net income per common and subordinated unit for the periods indicated:

	Year Ended December 31, 2013	Period from January 1, 2013 to May 16, 2013	Period from May 17, 2013 to December 31, 2013
	(in thousands, except per unit amounts)		
Net Income	$ 14,179	$ 6,982	$ 7,197
General partner interest in net income	7,188	6,982	206
Net income available to common and subordinated unitholders	$ 6,991	$	$ 6,991
Basic net income per common and subordinated unit	$ 0.17		$ 0.17
Diluted net income per common and subordinated unit	$ 0.17		$ 0.17
Basic average number of common and subordinated units outstanding	40,450		40,450
Equity Participation Unit equivalent units	1,008		1,008
Diluted average number of common and subordinated units outstanding	41,458		41,458

12. Major Customers and Concentration of Credit Risk

During the year ended December 31, 2013 and the period from November 13, 2012 to December 31, 2012, one non-affiliated customer, Phillips 66, accounted for $102.0 million (38%) and $11.2 million (32%) of TEP s total operating revenues, respectively. During the period from January 1, 2012 to November 12, 2012 and the year ended December 31, 2011, the same non-affiliated customer accounted for $68.9 million (31%) and $101.3 million (33%) of TEP Pre-Predecessor s total operating revenues, respectively. Phillips 66 was previously a part of ConocoPhillips and began trading separately on the New York Stock Exchange starting May 1, 2012. All of these revenues were earned in our Processing segment.

TIGT s principal delivery market area encompasses the states of Colorado, Kansas, Missouri, Nebraska and Wyoming. TIGT is a large transporter of natural gas to the mid-continent market. For the year ended December 31, 2013, TIGT delivered an average of 356,000 MMBtus per day of natural gas to this market. TIGT has a number of individually significant customers, including local natural gas distribution companies in the mid-continent area and major natural gas marketers. For the year ended December 31, 2013, approximately 93% of TIGT s transportation and storage revenues were generated under firm transportation and storage contracts. For the year ended December 31, 2013, TIGT s top ten non-affiliated customers accounted for approximately 60% of TIGT s total revenue. TIGT mitigates credit risk by requiring collateral or financial guarantees and letters of credit from customers with specific credit concerns. In support of credit extended to certain customers, TIGT had received prepayments of $2.8 million and $3.4 million at December 31, 2013 and 2012, respectively, included in the caption Accrued other current liabilities in the accompanying Consolidated Balance Sheets.

13. Equity-Based Compensation

Long-term Incentive Plan

Effective May 13, 2013, our general partner 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, including TD. Vesting and forfeiture requirements are at the discretion of the Board of Directors of our general partner at the time of the grant.

The LTIP limits the number of units that may be delivered pursuant to vested awards to 10,000,000 common units. Common units cancelled, forfeited or withheld to satisfy exercise prices or tax withholding obligations will be available for delivery pursuant to other awards. The plan is administered by the board of directors of our general partner or a committee thereof, which we refer to as the plan administrator.

The plan administrator may terminate or amend the LTIP at any time with respect to any units for which a grant has not yet been made. The plan administrator also has the right to alter or amend the LTIP or any part of the plan from time to time, including increasing the number of units that may be granted subject to the requirements of the exchange upon which the common units are listed at that time. However, no change in any outstanding grant may be made that would materially reduce the rights or benefits of the participant without the consent of the participant. The LTIP will expire on the earliest of (i) the date common units are no longer available under the plan for grants, (ii) termination of the plan by the plan administrator or (iii) May 13, 2023.

Equity Participation Units

On June 26, 2013, our general partner approved the grant of up to 1.5 million equity participation units (EPUs) for issuance to employees and of 177,500 EPUs to Section 16 officers under the LTIP. Effective the same date, 1.49 million EPUs were granted to employees and Section 16 officers of our general partner and its affiliates. Vesting of the EPUs is contingent upon TD s Pony Express Pipeline, which upon completion will consist of an approximately 690-mile oil pipeline connecting the Bakken Shale to Cushing, Oklahoma, being placed into service (the Pony Express Project) and will occur in two parts, with one-third vesting on the later of the Pony Express Project in-service date or May 13, 2015, and the remaining two-thirds vesting on the later of the Pony Express Project in-service date or May 13, 2017. If the Pony Express Project has not been placed in service by May 13, 2018, the EPUs will expire and no vesting of the EPUs will occur.

The EPU grants under the LTIP plan are measured at their grant date fair value. The EPUs granted are non-participating with respect to distributions, therefore the grant date fair value is discounted from the grant date fair value of TEP s common units for the present value of the expected future distributions during the vesting period. Total equity-based compensation cost related to the EPU grants of approximately $4.2 million was recognized during the year ended December 31, 2013. Of the total compensation cost, $1.8 million was recognized as compensation expense at TEP for the year ended December 31, 2013 and the remainder was allocated to TD. As of December 31, 2013, $18.3 million of total compensation cost related to non-vested EPUs is expected to be recognized over a weighted average period of 2.7 years, a portion of which will be charged to TD.

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The following table summarizes the changes in the EPUs outstanding for the year ended December 31, 2013:

	Shares	Weighted Average Grant Date Fair Value
Beginning of period		$
Granted	1,515,000	17.54
Forfeited	(40,750)	(17.49)
End of period	1,474,250	$ 17.54

14. Regulatory Matters

TIGT

Pony Express Abandonment FERC Docket CP12-495

On August 6, 2012, TIGT filed an application to: (1) abandon for FERC purposes the Pony Express Assets, and the natural gas service therefrom by transferring those assets to, PXP, which will convert the Pony Express Assets into crude oil pipeline facilities; and (2) construct and operate the Replacement Gas Facilities in order to continue service to existing natural gas firm transportation customers following the proposed conversion. We refer to this project as the Pony Express Abandonment. The FERC abandonment does not constitute an abandonment for accounting purposes. Pursuant to the terms of the Purchase and Sale Agreement filed with the FERC and cited by FERC in approving the Pony Express Abandonment, PXP was required to reimburse TIGT for the net book value of the Pony Express Assets plus other TIGT incurred costs required to construct the Replacement Gas Facilities and to arrange substitute gas transportation services to certain TIGT shippers.

The Pony Express Abandonment and completion of the Pony Express Project by PXP 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. By order issued September 12, 2013, TIGT was granted authorization to abandon the Pony Express Assets and construct the Replacement Gas Facilities. On October 7, 2013 TIGT commenced the mobilization of personnel and equipment for the construction of the Replacement Gas Facilities necessary to complete the Pony Express Abandonment to continue service to existing TIGT customers. In December 2013, TIGT removed the Pony Express Assets from gas service and sold those assets to PXP. Additional phases of the Pony Express Abandonment are expected to be completed during the second quarter of 2014.

15. Legal and Environmental Matters

Legal

Other than the matters discussed below, TEP is a defendant in various lawsuits arising from the day-to-day operations of their business. Although no assurance can be given, TEP believes, based on its 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 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 $0.3 million as of December 31, 2013. There was no reserve at December 31, 2012.

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TMID

West Frenchie Draw

TMID was 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. (Elkhorn), 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 arising in connection with the West Frenchie Draw Amine Plant in the principal amount of approximately $4.9 million plus interest, late charges, attorney s fees and costs from January 16, 2009. 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. 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 approximately $0.2 million 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.

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 s claim in the bankruptcy case has been withdrawn.

In August of 2013, the Company fully and finally settled all legal actions with Newpoint Gas Services and Elkhorn. In exchange for cash settlement payments from TMID, the parties released and dismissed all claims against each other with prejudice.

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 was previously a defendant in a lawsuit in state court in Douglas County, Nebraska (CI 10 9387384). Plaintiffs in the suit were Cornhusker Energy Lexington, LLC and its insurer, National Union Fire Insurance Company of Pittsburgh, Pennsylvania. The suit was initiated in February 2010. Plaintiffs alleged 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 requested 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. TD previously 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. The case went to trial in November 2013 and the jury returned a verdict in favor of TIGT on all claims. TIGT has filed for recovery of court costs.

System Failures

On May 4, 2013 and on June 13, 2013, a failure occurred on two separate segments of the TIGT pipeline system; one in Kimball County, Nebraska and one in Goshen County, Wyoming. The failures both resulted in the release 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 section in Kimball County, Nebraska were not material. The scope and cost of additional remediation activities related to the Goshen County failure are currently being evaluated.

Environmental

TEP is 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. TEP believes 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 TEP to incur significant costs. TEP had recorded environmental accruals of $5.0 million and $4.0 million at December 31, 2013 and December 31, 2012, respectively.

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 (LDAR) 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 letter from the U.S. EPA concerning settlement of this matter. Settlement negotiations with the U.S. EPA are continuing, including resolution of more recently identified LDAR issues.

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 TEP has requested that the portion of the site attributable to TEP be delisted from the National Priorities List.

16. 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.

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Gas Transportation and Storage

The Gas Transportation and Storage segment is engaged in the ownership and operation of FERC-regulated interstate natural gas pipelines and integrated natural gas storage facilities that provide services primarily to on-system customers such as third-party local distribution companies, or LDCs, industrial users and other shippers.

Processing

The Processing segment is engaged in 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, as well as water transportation services provided to producers.

Corporate and Other

Corporate and Other includes corporate overhead costs incurred subsequent to the IPO on May 17, 2013 which are not directly associated with the operations of our reportable segments, such as interest and fees associated with our revolving credit facility, public company costs reimbursed to TD, and equity-based compensation expense.

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 their respective operations.

Prior to the second quarter of 2013, TEP and TEP Predecessor Entity considered operating income to be its primary segment performance measure. Beginning in the second quarter of 2013, TEP began using Adjusted EBITDA as its primary segment performance measure as it provides a more meaningful measure to assess TEP s financial condition and results of operations as a public entity. Adjusted EBITDA, a non-GAAP measure, is defined as net income before interest, income taxes, depreciation and amortization, non-cash income or loss related to derivative instruments, non-cash long-term compensation expense, impairment losses, gains or losses on asset disposals and gains or losses on the repurchase, redemption or early retirement of debt.

The following tables set forth TEP and TEP Pre-Predecessor s segment information for the periods indicated:

	TEP						TEP Pre-Predecessor					
	Year Ended December 31, 2013			Period from November 13, 2012 to December 31, 2012			Period from January 1, 2012 to November 12, 2012			Year Ended December 31, 2011		
	Total Revenue	Inter-Segment	External Revenue	Total Revenue	Inter-Segment	External Revenue	Total Revenue	Inter-Segment	External Revenue	Total Revenue	Inter-Segment	Exte Reve
	(in thousands)			(in thousands)			(in thousands)					
ortation orage	$ 105,059	$ (1,920)	$ 103,139	$ 13,412	$ (96)	$ 13,316	$ 104,002	$ (696)	$ 103,306	$ 149,136	$ (601)	$ 148
ssing	164,569		164,569	21,972		21,972	116,986		116,986	158,508		158
rate and												

revenue	$ 269,628	$ (1,920)	$ 267,708	$ 35,384	$ (96)	$ 35,288		$ 220,988	$ (696)	$ 220,292	$ 307,644	$ (601)	$ 307

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	TEP						TEP Pre-Predecessor					
	Year Ended December 31, 2013			Period from November 13, 2012 to December 31, 2012			Period from January 1, 2012 to November 12, 2012			Year Ended December 31, 2011		
	Total Adjusted EBITDA	Inter-Segment	External Adjusted EBITDA	Total Adjusted EBITDA	Inter-Segment	External Adjusted EBITDA	Total Adjusted EBITDA	Inter-Segment	External Adjusted EBITDA	Total Adjusted EBITDA	Inter-Segment	Externa Adjuste EBITD
	(in thousands)			(in thousands)			(in thousands)					
s nsportation d storage	$ 52,967	$ (1,920)	$ 51,047	$ 2,862	$ (96)	$ 2,766	$ 52,459	$ (696)	$ 51,763	$ 72,864	$ (601)	$ 72,26
ocessing	23,192	1,920	25,112	2,744	96	2,840	18,302	696	18,998	25,564	601	26,16
rporate and her	(1,580)		(1,580)									
conciliation Income oss) before come Taxes:												
erest expense come), net			11,141			3,201			(1,661)			(2,10
xas Margin xes									279			29
preciation d ortization pense			29,549			4,086			20,647			22,72
ss on inguishment debt			17,526									
n-cash loss in) related to rivative truments			386			(273)						
n-cash mpensation pense			1,798									
come (loss) fore income es			$ 14,179			$ (1,408)			$ 51,496			$ 77,50

	TEP Total Assets	
	December 31, 2013	December 31, 2012
	(in thousands)	
Gas transportation and storage	$ 636,686	$ 741,595

Processing	326,599	294,219
Corporate and other	4,513	
Total assets	$ 967,798	$ 1,035,814

17. Selected Quarterly Financial Data (Unaudited)

The following tables summarize the unaudited quarterly statements operations for TEP and TEP Pre-Predecessor for 2013 and 2012:

	TEP Quarter Ended 2013			
	First	Second	Third	Fourth
	(in thousands, except per unit amounts)			
Total revenues	$ 60,258	$ 63,402	$ 63,259	$ 80,789
Operating income	$ 10,296	$ 8,870	$ 7,374	$ 14,170
Net income (loss)	$ 5,071	$ (11,727)	$ 7,006	$ 13,829
Net income attributable to partners	$ 5,071	$ 1,638	$ 140	$ 339
Net (loss) income allocable to limited partners	$ (1)	$ (13,365) (2)	$ 6,866	$ 13,490
Basic net (loss) income per limited partner unit	$ (1)	$ (0.33) (2)	$ 0.17	$ 0.33
Diluted net (loss) income per limited partner unit	$ (1)	$ (0.33) (2)	$ 0.17	$ 0.33

(1) No income was allocated to the limited partners until after the effective date of the IPO, May 17, 2013.

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(2) The second quarter of 2013 represented a prorated amount of net income allocated to the limited partners, based upon the number of days between the closing of the IPO on May 17, 2013 to June 30, 2013.

	TEP Pre-Predecessor Quarter Ended 2012				TEP 2012
	First	Second	Third	October 1, 2012 to November 12, 2012	November 13, 2012 to December 31, 2012
	(in thousands, except per unit amounts)				(in thousands, except per unit amounts)
Total revenues	$ 66,529	$ 59,519	$ 64,478	$ 29,766	$ 35,288
Operating income	$ 17,657	$ 13,448	$ 12,352	$ 6,656	$ 1,311
Net income (loss)	$ 17,147	$ 13,604	$ 13,865	$ 6,880	$ (1,408)
Net income (loss) attributable to partners	$ 17,147	$ 13,604	$ 13,865	$ 6,880	$ (1,408)

18. Subsequent Events

In January 2014, TD offered the Trailblazer Pipeline to TEP for purchase. A special committee of the Board of Directors of TEP s general partner, consisting solely of independent directors, has been formed and is evaluating the offer with assistance from external advisors engaged by the committee. The transaction has not been executed at this time and is subject to final negotiations and approval by the special committee and by the Board of Directors of TEP s general partner.

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Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosures

None.

Item 9A. 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

There have been no 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 December 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. Accordingly, this Annual Report on Form 10-K does 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 and, accordingly, a testing program will be executed throughout 2014.

Item 9B. Other Information

None.

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Part III

Item 10. Directors, Executive Officers and Corporate Governance

We are a limited partnership and, therefore, have no officers or directors. Unless otherwise indicated, references to our officers and directors in Items 10 through 14 of this Annual Report refer to the officers and directors of our general partner.

Management of Tallgrass Energy Partners, LP

Our general partner, Tallgrass MLP GP, LLC, manages our operations and activities on our behalf through its directors and officers. Our general partner is not elected by our unitholders and will not be subject to re-election in the future. Directors of our general partner oversee our operations. Tallgrass GP Holdings, LLC, which is owned and controlled by EMG, Kelso and certain members of our management team, is the sole owner of our general partner and has the right to appoint the entire board of directors of our general partner, including our independent directors. Unitholders are not entitled to elect the directors of our general partner or directly or indirectly participate in our management or operations. Our general partner will be liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made expressly non-recourse to it. Our general partner therefore may cause us to incur indebtedness or other obligations that are non-recourse to it.

As of December 31, 2013, the board of directors of our general partner had eight directors, three of whom the board has determined meet the independence standards established by the NYSE and the Exchange Act. The three independent directors are Jeffrey A. Ball (for purposes of Audit Committee participation only), Terrance D. Towner and Roy N. Cook. The NYSE does not require a publicly-traded limited partnership, such as ours, to have a majority of independent directors on the board of directors of its general partner or to establish a compensation or a nominating and corporate governance committee. However, our general partner is required to have an audit committee of at least three members, and all of its members are required to meet the independence and experience standards established by the NYSE and the Exchange Act, subject to certain transitional relief during the one-year period following the consummation of the IPO. As of December 31, 2013, the audit committee of the board of directors of our general partner had two members, each of whom meet the independence standards established by the NYSE and the Exchange Act. The audit committee of the board of directors of our general partner is required to add a third member prior to May 13, 2014.

In evaluating director candidates, Tallgrass GP Holdings, LLC assesses whether a candidate possesses the integrity, judgment, knowledge, experience, skill and expertise that are likely to enhance the board s ability to manage and direct our affairs and business, including, when applicable, to enhance the ability of committees of the board to fulfill their duties.

All of our general partner s executive officers are also executive officers of the general partner of Tallgrass Development and will devote such portion of their productive time to our business and affairs as is deemed reasonably required to manage and conduct our operations. Neither our general partner nor Tallgrass Development and its affiliates currently receive any management fee or other compensation in connection with the management or operation of our business. However, our partnership agreement requires us to reimburse our general partner and its affiliates for all expenses incurred and payments made on our behalf in connection with managing our business. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. In addition, the Omnibus Agreement requires us to reimburse Tallgrass Development s general partner and its affiliates for expenses they incur in providing general and administrative services to us. Neither our partnership agreement nor the Omnibus Agreement limits the amount of expenses for which our general partner or Tallgrass Development s general partner and its affiliates may be reimbursed.

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Directors and Executive Officers of Our General Partner

The following table shows information for the directors and executive officers of our general partner as of March 1, 2014.

Name	Age	Position with Tallgrass MLP GP, LLC
David G. Dehaemers, Jr.	53	President, Chief Executive Officer and Director
William R. Moler	48	Executive Vice President, Chief Operating Officer and Director
Gary J. Brauchle	40	Executive Vice President, Chief Financial Officer and Treasurer
George E. Rider	60	Executive Vice President, General Counsel and Secretary
Richard L. Bullock	59	Vice President, Human Resources, Tax and Risk Management
Frank J. Loverro	45	Director
Stanley de J. Osborne	44	Director
Jeffrey A. Ball	39	Director
John T. Raymond	43	Director
Terrance D. Towner	55	Director
Roy N. Cook	56	Director

Our directors hold office until the earlier of their death, resignation, removal or disqualification or until their successors have been elected and qualified. Officers serve at the discretion of the board of directors. There are no family relationships among any of our directors or executive officers.

David G. Dehaemers, Jr. has been a director and President and Chief Executive Officer of our general partner since February 2013. Mr. Dehaemers has served as a director of the general partner of Tallgrass Development and as the President and Chief Executive Officer of Tallgrass Development and its general partner since August 2012. Prior to joining our general partner, Mr. Dehaemers served as Co-Founder, Chief Executive Officer and Chief Investment Officer of Tallgrass MLP Fund I, L.P., a private MLP Investment Fund from 2008 to 2012. Mr. Dehaemers also served as Executive Vice President of corporate development at Inergy, LP (NRGY) from 2003 to 2007. Mr. Dehaemers played a role in NRGY s corporate development group, where he focused on developing its long-term expansion strategies in the midstream area, which included acquisitions and expansion projects in excess of $500 million. Mr. Dehaemers also was an owner of Inergy Holdings, L.P. (NRGP) when that entity went public in 2005. Before Inergy, Mr. Dehaemers was part of the executive management team of Kinder Morgan, Inc. and Kinder Morgan Energy Partners, LP from 1997 to 2003, where he served as the Chief Financial Officer from 1997 to 2000. In 2000, Mr. Dehaemers assumed responsibility for Kinder Morgan s corporate development efforts, in which role he and his team developed and executed Kinder Morgan s growth strategies. Mr. Dehaemers holds an undergraduate degree in Accounting from Creighton University in Omaha, Nebraska and is a Certified Public Accountant. He also holds a Juris Doctorate in Law from University of Missouri-Kansas City. We believe that Mr. Dehaemers education and experience, coupled with the leadership qualities demonstrated by his executive background, bring important experience and skill to the board of directors of our general partner.

William R. Moler has been a director and Chief Operating Officer and Executive Vice President of our general partner since February 2013 and has held the same positions for Tallgrass Development and its general partner since October 2012. From 2004 until his departure in October 2012, Mr. Moler served in various capacities with Inergy, L.P. and its affiliates, most recently as Senior Vice President and Chief Operating Officer of Inergy Midstream, L.P. and President and Chief Operating Officer Natural Gas Midstream Operations of Inergy, L.P. Prior to joining Inergy, L.P., Mr. Moler was with Westport Resources Corporation from 2002 to 2004, where he served as both General Manager of Marketing and Transportation Services and General Manager of Westport Field Services, LLC. Prior to Westport, Mr. Moler served in various leadership positions at Kinder Morgan, Inc. from 1988 to 2002. Mr. Moler earned a Bachelor of Science degree in Mechanical Engineering from Texas Tech University in 1988. We believe that as a result of his background and knowledge, as well as the attributes of leadership demonstrated by his executive experience, Mr. Moler brings substantial experience and skill to the board of directors of our general partner.

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Gary J. Brauchle has been Executive Vice President, Chief Financial Officer and Treasurer of our general partner since February 2013 and has held the same positions for Tallgrass Development and its general partner since November 2012. Prior to joining Tallgrass, Mr. Brauchle was Vice President and Chief Accounting Officer at McDermott International, Inc., a global engineering and construction company serving the oil and gas industry during 2012 and as Corporate Controller from 2010 to 2012. He joined McDermott in 2003 and served in various positions of increasing responsibility, including as Director of Internal Audit from 2005 to 2007 and as Director of Operational Accounting and Assistant Controller for an operating subsidiary from 2007 to 2008 and 2008 to 2010, respectively. Mr. Brauchle also served in the Houston office of PricewaterhouseCoopers energy and utilities practice from 1997 to 2003, including as a Manager from 2001 to 2003, and with a focus on midstream master limited partnerships, or MLPs. Mr. Brauchle was a postgraduate technical assistant at the Financial Accounting Standards Board (FASB) from 1996 to 1997. Mr. Brauchle is a Certified Public Accountant and a graduate of Texas A&M University, where he received a Master of Science in Accounting in 1996 and a Bachelor of Business Administration in Accounting in 1995.

George E. Rider has been Executive Vice President, General Counsel and Secretary of our general partner since February 2013 and has held the same positions for Tallgrass Development and its general partner since August 2012. From 2008 to August 2012, Mr. Rider was Vice President and General Counsel for Tallgrass Capital, LLC and its affiliate, Tallgrass MLP Fund I, L.P., a private MLP Investment Fund. From 1986 to 2008, Mr. Rider was an attorney with the law firm of Stinson Morrison Hecker LLP, becoming a partner in 1987. Mr. Rider holds an undergraduate degree from Phillips University and a Juris Doctorate in Law from the University of Kansas, where he was a member of Order of the Coif.

Richard L. Bullock has been Vice President of Human Resources, Tax and Risk Management of our general partner since February 2013 and has held the same positions for Tallgrass Development and its general partner since November 2012. Previously, Mr. Bullock served as the Vice President, Chief Financial Officer and Treasurer of Tallgrass Development and its general partner. Mr. Bullock previously served as Vice President and Chief Financial Officer of Tallgrass MLP Fund I, L.P. from 2008 to 2011. Prior to Tallgrass, Mr. Bullock worked at Kinder Morgan Energy Partners, L.P. Mr. Bullock joined Kinder Morgan Energy Partners, L.P. in 1997 where he served as Vice President, Controller and Chief Accounting Officer through 2002 and, thereafter served as Vice President-Tax through October 2008. In those roles Mr. Bullock was principally responsible for all quarterly and annual SEC filings, integrating the accounting and financial reporting functions for acquisitions, tax compliance and tax planning for both Kinder Morgan Energy Partners, L.P. and Kinder Morgan, Inc. Mr. Bullock is a Certified Public Accountant. He received his undergraduate degree in Accounting from Missouri State University in Springfield, Missouri.

Frank J. Loverro has served as a director of our general partner since February 2013 and has held the same position for the general partner of Tallgrass Development since August 2012. Mr. Loverro joined Kelso in 1993 and has been Managing Director since 2004. He spent the preceding three years in the private equity investment and high yield groups at The First Boston Corporation. Mr. Loverro is also a director of Delphin Shipping LLC, Hunt Marcellus, LLC and Poseidon Containers Holdings LLC. Mr. Loverro was also a director of Buckeye GP LLC. Mr. Loverro received a B.A. in Economics with Distinction from the University of Virginia in 1991. Mr. Loverro has extensive experience in corporate financing and in evaluating the financial performance and operations of companies across a variety of business sectors, including the energy sector. We believe that this background, in addition to Mr. Loverro s valuable experience serving on the boards of various public and private companies, provides an important source of insight and perspective to the board of directors of our general partner.

Stanley de J. Osborne has served as a director of our general partner since February 2013 and has held the same position for the general partner of Tallgrass Development since August 2012. Mr. Osborne joined Kelso in 1998 and has been Managing Director since 2007. He spent the preceding two years as an Associate at Summit Partners. He spent the previous three years at J.P. Morgan & Co. as an Associate in the Private Equity Group and an Analyst in the Financial Institutions Group. Mr. Osborne is also a director of Global Geophysical Services, Inc., Hunt Marcellus, LLC, Logan s Roadhouse, Inc., Traxys S.a.r.l and Power Team Services. Mr. Osborne was also director of CVR Energy, Inc. Mr. Osborne received a B.A. in Government from Dartmouth College in 1993. Mr. Osborne has extensive experience in corporate financing and in evaluating the financial performance and operations of companies across a variety of business sectors, including the energy sector. We believe that this background, in addition to Mr. Osborne s valuable experience serving on the boards of various public and private companies, provides an important source of insight and perspective to the board of directors of our general partner.

Jeffrey A. Ball has served as a director and Chairman of the Audit Committee of our general partner since February 2013 and as a director of the general partner of Tallgrass Development since August 2012. Mr. Ball is a Managing Director at EMG, a diversified natural resource private equity fund manager. Prior to joining EMG in 2007, Mr. Ball was a Director of investment banking at Credit Suisse Securities (USA), LLC covering the energy industry with a particular focus on MLPs and the midstream sector. Mr. Ball currently serves on the Boards of Ferus Inc., Ferus GP LLC, Ferus Natural Gas Fuels Inc., Ferus Natural Gas Fuels GP, LLC and Ferus Natural Gas Fuels (CNG), LLC. Mr. Ball received a B.S. in Economics from the Wharton School at the University of Pennsylvania with dual concentrations in Finance and Accounting. We believe that Mr. Ball s experience with mergers & acquisitions and financings of a variety of MLPs and other midstream assets provides a valuable resource to the board of directors of our general partner.

John T. Raymond has served as a director of our general partner since February 2013 and has held the same position for the general partner of TD since August 2012. Mr. Raymond is an owner and founder of EMG, a diversified natural resource private equity fund manager with approximately $8.4 billion of total investor commitments (including co-investments), and has been Managing Partner and CEO since EMG s inception in 2006. Previous to that time, Mr. Raymond held leadership positions with various energy companies, including President and CEO of Plains Resources Inc., President and Chief Operating Officer of Plains Exploration and Production Company and Director of Development for Kinder Morgan, Inc. Mr. Raymond currently serves on numerous other boards, including the board of directors of each of NGL Energy Holdings, LLC, the general partner of NGL Energy Partners, LP, Plains All American GP LLC, the general partner of Plains All American Pipeline, LP, and PAA GP Holdings LLC, the general partner of Plains GP Holdings, LP. We believe that Mr. Raymond s experience with investment in and management of a variety of upstream and midstream assets and operations provides a valuable resource to the board of directors of our general partner. Mr. Raymond received a BSM degree from the A.B. Freeman School of Business at Tulane University with dual concentrations in finance and accounting.

Terrance D. Towner has served as a director of our general partner since August 2013 and has also served as a member of the audit committee of our general partner since August 2013. Mr. Towner presently serves as Executive Vice Chairman of Watco Companies and previously served in various capacities for the company including as President, COO and CFO of Watco Companies, a Kansas based transportation company that, among other things, operates thirty short line railroads in the United States and Australia. Mr. Towner s responsibilities included overseeing all operations, safety, quality, human resources, information services and financial performance of Watco s transportation, mechanical, and terminal and port divisions. Prior to joining Watco, Mr. Towner spent thirteen years in banking including three years as President and CEO of First State Bank & Trust Company of Pittsburg, Kansas. He also served for five years as President of Pitsco, a company that develops and markets education products, and approximately two years as a financial and strategic consultant with Grant Thornton. As a consultant, Mr. Towner advised his clients in a broad range of industries including manufacturing, consumer products, electronics, software development, staffing and professional placement and other financial services. Following his departure from Grant Thornton, Mr. Towner acquired Joplin.com, an internet service provider located in Joplin, Missouri serving approximately 6,000 customers in southwestern Missouri. In 2001, Mr. Towner sold the company to Empire District Electric Company, a public utility. During this time, Mr. Towner also owned, operated and published a financial newsletter called The Regional Stock Monitor which provided financial analysis and news on a number of public companies located throughout the midwest. Mr. Towner earned his bachelor s degree in Economics from Pittsburg State University in 1981 and his MBA from Pittsburg State University in 1993.

Roy N. Cook has served as a director of our general partner since September 2013. From 2001 to 2013, Mr. Cook was employed by, and held a variety of roles within, the terminals division of Kinder Morgan, focusing on acquisitions, management, design and operations and specializing in the dry bulk side of the terminals business. Prior to 2001, Mr. Cook owned and managed several business in the service industry, including Milwaukee Bulk Terminals, Inc. and Dakota Bulk Terminals, Inc., each of which were sold to Kinder Morgan in 2001. Mr. Cook currently owns several small businesses across diverse industries, including a self-storage business, an electrical service company and a commercial real estate management and development company. He graduated from Kansas State University in 1979 with a B.S. degree in Agriculture Economics.

Audit Committee

The Board of Directors of our General Partner has a standing audit committee which is currently composed of two directors, Jeffrey A. Ball and Terrance D. Towner. Each audit committee member has past experience in accounting or related financial management experience. The board has determined that both of our audit committee members are independent under Section 303A.02 of the NYSE listing standards and Rule 10A-3 of the Securities Exchange Act of 1934, as amended. In making the independence determination, the board considered the requirements of the NYSE, the SEC and our Code of Business Conduct and Ethics. Among other factors, the board considered current or previous employment with us, our auditors or their affiliates by the director or his immediate family members, ownership of our voting securities and other material relationships with us. The audit committee has adopted a charter, which has been ratified and approved by the board of directors.

Jeffrey A. Ball has been designated by the board as the audit committee s financial expert meeting the requirements promulgated by the SEC and set forth in Item 407(d) of Regulation S-K of the Securities Exchange Act of 1934, as amended, based upon his education and employment experience as more fully detailed in Mr. Ball s biography set forth above. Mr. Ball also acts as the Chairman of our audit committee.

Corporate Governance Guidelines and Code of Business Conduct and Ethics

Our general partner has adopted Corporate Governance Guidelines and a Code of Business Conduct and Ethics applicable to all of our employees, officers and directors with regard to Partnership-related activities. The Corporate Governance Guidelines and the Code of Business Ethics incorporate guidelines designed to deter wrongdoing and to promote honest and ethical conduct and compliance with applicable laws and regulations. They also incorporate expectations of our employees that enable us to provide accurate and timely disclosure in our filings with the SEC and other public communications. A copy of the Corporate Governance Guidelines and the Code of Business Conduct and Ethics are available to any person, free of charge, at our website at www.tallgrassenergy.com.

Item 11. Executive Compensation

Executive Compensation

We and our general partner were formed in Delaware in February 2013. We do not directly employ any of the persons responsible for managing our business. Our business is managed and operated by the directors and executive officers of our general partner. All employees, including the executive officers of our general partner, are employed by an affiliate of our general partner, Tallgrass Management, LLC. Compensation of our executive officers is set by Tallgrass GP Holdings, LLC. The Partnership reimburses TD for all salaries, related benefits and compensation expenses for the employees of Tallgrass Management, LLC who provide services to the Partnership pursuant to an allocation agreed upon between TD and the Partnership under the terms of the Omnibus Agreement. Other than the employment agreement with our chief executive officer, David G. Dehaemers, Jr., none of our executive officers have entered into any employment agreements with Tallgrass Management, LLC, our general partner or any other affiliate.

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Summary Compensation Table

The following table reflects the total compensation of the principal executive officer and of the three other most highly compensated executive officers of our general partner for 2013 (the named executive officers) for services rendered to all Tallgrass-related entities, including the Partnership, Tallgrass Management, LLC and TD for the fiscal year ending December 31, 2013.

	Year	Salary	Bonus (1)	EPU Awards (2)	All Other Compensation (3)	Total
David G. Dehaemers, Jr. *President and Chief Executive Officer and Director*	2013	$ 300,000	$ 100,000	$	$ 33,186	$ 433,186
William R. Moler *Executive Vice President, Chief Operating Officer and Director*	2013	$ 275,000	$ 200,000	$ 874,500	$ 30,578	$ 1,380,078
Gary J. Brauchle *Executive Vice President, Chief Financial Officer and Treasurer*	2013	$ 250,000	$ 200,000	$ 874,500	$ 26,432	$ 1,350,932
George E. Rider *Executive Vice President, General Counsel and Secretary*	2013	$ 250,000	$ 200,000	$ 874,500	$ 27,893	$ 1,352,393

(1) Represents a discretionary bonus paid in 2014 based on 2013 performance.

(2) The amounts in this column represent the aggregate grant date fair value determined in accordance with ASC Topic 718 for equity participation units, or EPUs, granted in June 2013 under the Tallgrass MLP GP, LLC Long-Term Incentive Plan. Pursuant to SEC rules, the amounts shown in the Summary Compensation Table for awards subject to performance conditions are based on the probable outcome as of the date of grant and exclude the impact of estimated forfeitures. The EPU grants are measured at their grant date fair value of $17.49. The EPUs are non-participating, therefore the grant date fair value is discounted from the grant date fair value of TEP s common units for the present value of the expected (but non-participating) future dividends during the vesting period. For additional information, see Note 13 *Equity-Based Compensation* to our Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data in this Annual Report. These amounts do not correspond to the actual value that will be recognized by the executive.

(3) The amounts in the column include the following: contributions under the 401(k) savings plan (includes $30,000 for Mr. Dehaemers, $27,500 for Mr. Moler, $23,460 for Mr. Brauchle and $24,923 for Mr. Rider) and the dollar value of premiums paid for group life, accidental death and dismemberment insurance.

Employment Agreement

On May 17, 2013, Mr. Dehaemers entered into an amended and restated employment agreement with Tallgrass Management, LLC, Tallgrass Development GP, LLC, Tallgrass GP Holdings, LLC and our general partner pursuant to which he agreed to serve as their President and Chief Executive Officer. Under the terms of the employment agreement, Mr. Dehaemers is entitled to receive an annual salary of $300,000. In addition, Mr. Dehaemers is entitled to receive (i) benefits that are normally provided to senior executives of Tallgrass Management, LLC, (ii) reimbursement for all ordinary and necessary out-of-pocket expenses incurred by Mr. Dehaemers, and (iii) a policy of directors and officers liability insurance.

Mr. Dehaemers employment is at-will and may be terminated at any time. For a discussion of certain payments that Mr. Dehaemers may be entitled to upon the termination of his employment, please read Potential Payments Upon Termination or a Change in Control.

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Outstanding Equity Awards at Fiscal Year-End

The following table reflects all outstanding equity awards of our named executive officers as of December 31, 2013.

	Equity Participation Unit Awards (1)					
	Number of EPU Awards That Have Not Vested	Market Value of EPU Awards That Have Not Vested		Number of Unearned EPUs That Have Not Vested (2)	Market or Payout Value of Unearned EPUs That Have Not Vested (3)	
David G. Dehaemers, Jr.		$			$	
William R. Moler		$		50,000	$	874,500
Gary J. Brauchle		$		50,000	$	874,500
George Rider		$		50,000	$	874,500

(1) The plan administrator may make grants of equity participation units under the plan containing such terms as the plan administrator shall determine, including the period over which equity participation units granted will vest. The plan administrator, in its discretion, may base its determination upon the achievement of specified financial or other performance objectives. The award agreements pursuant to which the EPUs set forth above were granted to provide for the settlement of the EPUs in common units.

(2) Vesting of the EPUs is contingent upon the Pony Express Project being placed into commercial service and will occur in two parts, with one-third vesting on the later of the Pony Express in-service date or May 13, 2015, and the remaining two-thirds vesting on the later of the Pony Express in-service date or May 13, 2017. If the Pony Express Project has not been placed in service by May 13, 2018, the EPUs will expire and no vesting of the EPUs will occur.

(3) The amounts in this column represent the aggregate grant date fair value determined in accordance with ASC Topic 718 for equity participation units, or EPUs, granted in June 2013 under the Tallgrass MLP GP, LLC Long-Term Incentive Plan. The EPU grants are measured at their grant date fair value of $17.49. The EPUs are non-participating, therefore the grant date fair value is discounted from the grant date fair value of TEP s common units for the present value of the expected (but non-participating) future dividends during the vesting period. For additional information, see Note 13 *Equity-Based Compensation* to our Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data in this Annual Report. These amounts do not correspond to the actual value that will be recognized by the executive.

Long-Term Incentive Plan

Our general partner has adopted the Tallgrass MLP GP, LLC Long-Term Incentive Plan, or LTIP, for officers, directors, employees and consultants of our general partner and its affiliates. We may issue our executive officers long-term equity based awards under the plan, which awards are intended to compensate the officers based on the performance of our common units and their continued employment during the vesting period, as well as align their long-term interests with those of our unitholders. We are responsible for our allocable share of the cost of awards granted under the LTIP. For more information regarding the LTIP, see Note 13 *Equity-Based Compensation* to our Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data of this Annual Report.

Potential Payments Upon Termination or Change of Control

Dehaemers Employment Agreement

The employment agreement for Mr. Dehaemers provides that he will receive a severance payment equal to $900,000, payable in a lump sum within 60 days after the termination of his employment, in the event his employment is terminated without cause or in the event he resigns for good reason. Under Mr. Dehaemers employment agreement:

Cause means (i) his conviction of, or please of nolo contendere to, any crime or offense constituting a felony under applicable law; (ii) his commission of fraud or embezzlement against Tallgrass

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Management, LLC or certain of its affiliates; (iii) gross neglect by Mr. Dehaemers of, or gross or willful misconduct of Mr. Dehaemers in connection with the performance of, his duties that is not cured within 30 days of receiving a written notice of such gross neglect or gross or willful misconduct; (iv) Mr. Dehaemers willful failure or refusal to carry out the reasonable and lawful instructions of the board of managers of Tallgrass GP Holdings, LLC; (v) Mr. Dehaemers failure to perform the duties and responsibilities of his office as his primary business activity; (vi) a judicial determination that Mr. Dehaemers has breached his fiduciary duties with respect to Tallgrass Management, LLC or certain of its affiliates; or (vii) Mr. Dehaemers willful and material breach of his obligations under the operating agreements of Tallgrass GP Holdings, LLC, Tallgrass Development GP, LLC, Tallgrass Development or our general partner, in his capacity as an officer of such entities.

Good reason means (i) during the period prior to Tallgrass Management, LLC or certain of its affiliates accessing the public markets (through an initial public offering, merger or otherwise), Kelso and EMG and their respective affiliates cease to hold, in the aggregate, a majority of certain equity interests issued to them on or about the date of our initial public offering; (ii) a material diminution of Mr. Dehaemers duties and responsibilities to Tallgrass Management, LLC or certain of its affiliates to a level inconsistent with those of a chief executive officer; (iii) a material reduction in Mr. Dehaemers cash compensation or the aggregate welfare benefits provided to him (excluding any reduction that is not limited to him specifically); (iv) a willful or intentional breach of his employment agreement by Tallgrass Management, LLC; or (v) a willful or intentional breach by Tallgrass GP Holdings, LLC, Tallgrass Development GP, LLC, Tallgrass Development, our general partner or certain investors in Tallgrass GP Holdings, LLC of a material provision of the applicable operating agreements of such entities that has a material and adverse effect on Mr. Dehaemers.

In addition, under the terms of his employment agreement, Mr. Dehaemers has agreed not to compete with Tallgrass Management, LLC or certain of its affiliates and not to solicit Tallgrass Management, LLC s or any of its affiliates employees or interfere with certain business relationships during the term of his employment and for one year thereafter.

LTIP Awards

Awards under the LTIP may vest and/or become exercisable, as applicable, upon a change in control of us or our general partner, if so provided by the plan administrator at the time of the grant. The consequences of the termination of a grantee s employment, consulting arrangement or membership on the board of directors will be determined by the plan administrator in the terms of the relevant award agreement

Compensation of Directors

Officers or employees of TD or its affiliates, including directors affiliated with EMG or Kelso, who also serve as directors of our general partner do not receive additional compensation for such service. Directors of our general partner who are not also officers or employees of TD or its affiliates receive cash compensation as follows:

Quarterly cash retainer payments of $10,000, resulting in an effective annual cash retainer of $40,000.

For serving as the audit committee chair or the conflicts committee chair, an annual committee chair retainer of $5,000.

All directors are also reimbursed for out-of-pocket expenses in connection with their service as directors, including costs incurred to attend meetings. Each director is fully indemnified by us for actions associated with being a director to the fullest extent permitted under Delaware law pursuant to our partnership agreement. Directors of our general partner are also eligible to receive grants under the LTIP. On February 26, 2014, the board of directors of our general partner approved a grant of 3,000 EPUs to each director of our general partner who is not an officer or employee of TD or its affiliates. Vesting of the EPUs granted to our independent directors is contingent upon the Pony Express Project being placed in service and will occur in three parts, with one-third vesting on the later of the Pony Express Project in-service date or May 13, 2015, one-third vesting on the later of the Pony Express Project in-service date or May 13, 2016 and the remaining one-third vesting on the later of the Pony Express Project in-service date or May 13, 2017. If the Pony Express Project has not been placed in service by May 13, 2018, the EPUs will expire and no vesting of the EPUs will occur.

The following table sets forth certain information with respect to our non-employee director compensation during the year ended December 31, 2013.

Name and Principal Position	Fees Earned or Paid in Cash (1)	EPU Awards	Non-Equity Incentive Plan Compensation	All Other Compensation	Total
Terrance D. Towner	$ 20,000	$	$	$	$ 20,000
Roy N. Cook	$ 10,000	$	$	$	$ 10,000

(1) Includes cash retainer, meeting fees and committee chair fees.

Compensation Committee Interlocks and Insider Participation

The listing rules of the NYSE do not require us to maintain, and we do not maintain, a compensation committee.

Mr. Dehaemers, as President and Chief Executive Officer, and Mr. Moler, as Executive Vice President and Chief Operating Officer, participate in their capacity as a director of our general partner in the deliberations of the Board concerning executive officer compensation. In addition, Mr. Dehaemers makes recommendations to the board of directors regarding named executive officer compensation, but Mr. Dehaemers abstains from, and is not present for, any decisions regarding his compensation.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The following table sets forth the beneficial ownership of our units as of March 1, 2014 owned by:

- each person known by us to be a beneficial owner of more than 5% of the units;
- each of the directors of our general partner;
- each of the named executive officers of our general partner; and
- all directors and executive officers of our general partner as a group.

The amounts and percentage of units beneficially owned are reported on the basis of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, a person is deemed to be a beneficial owner of a security if that person has or shares voting power, which includes the power to vote or to direct the voting of such security, or investment power, which includes the power to dispose of or to direct the disposition of such security. Except as indicated by footnote, the persons named in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable.

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Percentage of total units to be beneficially owned is based on 24,300,000 common units and 16,200,000 subordinated units outstanding as of March 1, 2014.

Name of Beneficial Owner (1)	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned	Percentage of Total Common and Subordinated Units Beneficially Owned
Tallgrass Operations, LLC (2)	9,700,000	40%	16,200,000	100%	64%
Salient Capital Advisors, LLC (3)	1,569,317	6%			4%
David G. Dehaemers, Jr.	150,000	1%			*
William R. Moler					
Gary J. Brauchle	7,083	*			*
George E. Rider	2,500	*			*
Richard L. Bullock	4,500	*			*
Frank J. Loverro					
Stanley de J. Osborne					
Jeffrey A. Ball	20,000	*			*
John T. Raymond	100,000	*			*
Roy N. Cook	20,000	*			*
Terrance D. Towner	2,000	*			*
All directors and executive officers as a group (eleven persons)	306,083	1%			1%

* Less than 1%

(1) Unless otherwise indicated, the address for all beneficial owners in this table is c/o Tallgrass Energy Partners, LP, 6640 W. 143rd Street, Suite 200, Overland Park, Kansas 66223, Attn: General Counsel.

(2) Tallgrass Development GP, LLC, as the general partner of Tallgrass Development, which is the sole owner of Tallgrass Operations, LLC, has the sole voting and dispositive power with respect to the common units and the subordinated units owned by Tallgrass Operations, LLC. Tallgrass Development GP, LLC is controlled by its sole member, Tallgrass GP Holdings, LLC. Tallgrass GP Holdings, LLC is, in turn, controlled by its board of directors, which currently consists of the following: David G. Dehaemers, Jr., William R. Moler, Frank J. Loverro, Stanley de J. Osborne, Jeffrey A. Ball and John T. Raymond. Each of the members of the board of directors of Tallgrass GP Holdings, LLC may be deemed to beneficially own the common units and the subordinated units owned by Tallgrass Operations, LLC; however, each disclaims beneficial ownership.

(3) As reported on Schedule 13G as of December 31, 2013 and filed with the SEC on January 13, 2014. The business address for Salient Capital Advisors, LLC is 4265 San Felipe, 8th Floor, Houston, Texas 77027.

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Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information about TEP s common units that may be issued under equity compensation plans as of December 31, 2013:

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted average grant date fair value of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders (1)	1,474,250	$ 17.54	8,525,750
Equity compensation plans not approved by security holders (2)		$	
Total	1,474,250	$ 17.54	8,525,750

(1) Amounts shown represent equity participation unit awards outstanding under the LTIP as of December 31, 2013. The outstanding awards will be settled in common units pursuant to the terms of the award agreements and are not subject to an exercise price.

(2) There were no equity compensation plans in place except for the LTIP.

For additional information regarding the LTIP, see Note 13 *Equity-Based Compensation* to our Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data of this Annual Report.

Item 13. Certain Relationships and Related Transactions, and Director Independence

As of March 1, 2014, TD owned 9,700,000 common units and all of our subordinated units representing 64% of our outstanding common and subordinated units. In addition, our general partner owns 826,531 general partner units representing a 2% general partner interest in us and all of the incentive distribution rights.

Distributions and Payments to Our General Partner and Its Affiliates

The following information summarizes the distributions and payments made or to be made by us to our general partner and its affiliates in connection with our formation, ongoing operation and any liquidation of us. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm s-length negotiations.

Formation Stage

The aggregate consideration received by our general partner and its affiliates, including TD, in connection with the IPO:

- 9,700,000 common units received by TD;
- 16,200,000 subordinated units received by TD;
- 826,531 general partner units representing a 2% general partner interest received by our general partner;
- all of the IDRs received by our general partner;

the assumption by TEP of approximately $400 million of indebtedness from TD;

a cash payment of approximately $85.5 million from TEP to TD as reimbursement for certain capital expenditures made in connection with the contributed assets; and

a cash distribution of $31.2 million from TEP to TD, equal to the net proceeds from the exercise of the underwriter s option to purchase additional units, also as reimbursement for capital expenditures made in connection with the contributed assets

Operational Stage

Distributions of available cash to our general partner and its affiliates. We will generally make distributions of available cash 98% to common and subordinated unitholders pro rata, including TD as the holder of an aggregate of 9,700,000 common units and all of the subordinated units, and 2% to our general partner, as the holder of our general partner units. In addition, if distributions of available cash exceed the MQD and other higher target levels specified in our partnership agreement, our general partner, as the holder of the IDRs, will be entitled to increasing percentages of the distributions, up to 48% of the distributions above the highest target level. Assuming we have sufficient available cash to pay the full MQD on all of our outstanding units for four quarters, our general partner and its affiliates would receive an annual distribution of approximately $1.0 million on their general partner units and $29.8 million on their common and subordinated units.

Payments to our general partner and its affiliates. Neither our general partner nor TD s general partner and its affiliates receive a management fee or other compensation for managing us. Our general partner and TD s general partner and its affiliates are reimbursed, however, for all direct and indirect expenses incurred on our behalf pursuant to our partnership agreement and the Omnibus Agreement. Neither our partnership agreement nor the Omnibus Agreement limit the amount of expenses for which our general partner or TD s general partner and its affiliates may be reimbursed. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us.

Withdrawal or removal of our general partner. If our general partner withdraws or is removed, its general partner interest and its IDRs will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.

Liquidation Stage. Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their particular capital account balances, as further detailed in our limited partnership agreement.

Agreements with Affiliates in Connection with the IPO

We entered into various documents and agreements with TD and its other affiliates in connection with the IPO. These are primarily related to our formation, including the vesting of assets in, and the assumption of liabilities by, us and our subsidiaries, and the application of the proceeds of the IPO. These agreements were not the result of arm s length negotiations.

Omnibus Agreement

Upon the closing of the IPO, we entered into an Omnibus Agreement with TD, its general partner and our general partner that governs our relationship with them regarding the following matters:

- the provision by TD s general partner to us of certain administrative services and our agreement to reimburse it for such services;

- the provision by TD s general partner of such employees as may be necessary to operate and manage our business, and our agreement to reimburse it for the expenses associated with such employees;

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- certain indemnification obligations;
- our use of the name Tallgrass and related marks; and
- our right of first offer to acquire certain assets, including each of the Retained Assets from TD, if Tallgrass Development decides to sell such assets.

Reimbursement of General and Administrative Expenses

Pursuant to the Omnibus Agreement, the general partner of TD performs, or causes its affiliates to perform, centralized corporate, general and administrative services for us, such as legal, corporate recordkeeping, planning, budgeting, regulatory, accounting, billing, business development, treasury, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, investor relations, cash management and banking, payroll, internal audit, taxes and engineering. In exchange, we reimburse it for expenses incurred in providing these services. The reimbursements to our general partner and TD s general partner and its affiliates are made prior to cash distributions to our common unitholders. The Omnibus Agreement further provides that we will reimburse the general partner of TD and its affiliates for our allocable portion of the premiums on any insurance policies covering our assets. We anticipate reimbursement to TD s general partner and its affiliates will vary with the size and scale of our operations, among other factors.

Indemnification

Under the terms of the Omnibus Agreement, TD is required to indemnify us from liabilities arising out of any federal, state and local income tax liabilities attributable to the ownership and operation of the assets contributed to us in connection with the IPO until 60 days after the applicable statute of limitations. TD also agreed to use commercially reasonable efforts to obtain indemnification from Kinder Morgan for losses suffered or incurred by us with respect to the assets contributed to us as part of the IPO, to the extent that Kinder Morgan is obligated to indemnify TD under the purchase and sale agreement pursuant to which TD acquired the contributed assets and remit any proceeds received from Kinder Morgan pursuant to such indemnification obligations to us.

Kinder Morgan s indemnity obligations under the Kinder Morgan purchase agreement generally survived through February 13, 2014, although certain specified indemnities last for longer periods of time. Under the Omnibus Agreement, we have agreed to indemnify TD for events and conditions associated with the operation of the contributed assets that occur on or after the closing of the IPO.

Right of First Offer

Under the terms of the Omnibus Agreement, TD has granted us a right of first offer, for so long as TD or its affiliates, individually or as part of a group, control our general partner, on (i) the Retained Assets and (ii) any assets that are hereafter developed, constructed or acquired by TD or its subsidiaries (excluding the Partnership and its subsidiaries) for the purpose of processing natural gas in Natrona, Converse or Campbell counties in Wyoming, which we refer to collectively as the ROFO Assets. If TD or any of its affiliates decide to attempt to sell (other than to an affiliate of TD, excluding TEP and its subsidiaries) a ROFO Asset, TD or its affiliate will notify us in advance and, prior to selling such ROFO Asset to a third party, will negotiate with us exclusively and in good faith for a period of 45 days in order to give us an opportunity to enter into definitive documentation for the purchase and sale of such ROFO Asset on terms that are mutually acceptable to TD or its affiliate and us. If we and TD or its affiliate have not entered into a letter of intent or a definitive purchase and sale agreement with respect to such ROFO Asset within such 45-day period, TD or its affiliate will have the right to sell such ROFO Asset to a third party following the expiration of such 45-day period on any terms that are acceptable to TD or its affiliate and such third party. Our decision to acquire or not to acquire a ROFO Asset pursuant to this right will require the approval of the conflicts committee of the board of directors of our general partner.

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Amendment and Termination

The Omnibus Agreement can be amended by written agreement of all parties to the agreement. However, we may not agree to any amendment or modification that would, in the determination of our general partner, be adverse in any material respect to the holders of our common units without the prior approval of the conflicts committee. In the event of (i) a change in control (as defined in the Omnibus Agreement) of the partnership or (ii) the removal of Tallgrass MLP GP, LLC as our general partner in circumstances where cause (as defined in our partnership agreement) does not exist and the common units held by our general partner and its affiliates were not voted in favor of such removal, the Omnibus Agreement (other than the indemnification and reimbursement provisions therein) will be terminable by TD, and we will have a 90-day transition period to cease our use of the name Tallgrass and related marks.

Competition

Under our partnership agreement, TD and its affiliates are expressly permitted to compete with us. TD and any of its affiliates, including EMG and Kelso may acquire, construct or dispose of additional transportation, storage and processing or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets.

Contracts with Affiliates

Pony Express Abandonment

TIGT entered into a Purchase and Sale Agreement, or the Pony Express PSA, with PXP, a wholly-owned subsidiary of TD, whereby TIGT (i) sold the Pony Express Assets to PXP, which is converting those facilities into a crude oil pipeline serving the Bakken Shale and other nearby oil producing basins and (ii) constructed the Replacement Gas Facilities in order to continue service to existing natural gas firm transportation customers following the abandonment and sale of the Pony Express Assets to PXP. The purpose of these coordinated actions was to efficiently re-deploy existing natural gas transmission assets to meet the growing market need to transport oil supplies from the Bakken shale while continuing to operate our natural gas transportation facilities to meet all current and expected needs of its natural gas customers.

Pursuant to the Pony Express PSA, in December 2013 we sold the Pony Express Assets to PXP. TD is currently converting the Pony Express Assets into a crude oil pipeline and constructing an approximately 260-mile extension of the pipeline to provide access to Cushing, Oklahoma. At TIGT, we are also constructing the Replacement Gas Facilities, which consist of one new mainline compressor station, two lateral pipelines, two booster compression units and certain auxiliary facilities, in order to continue service to certain existing firm shippers who desire continued firm service.

Pursuant to the Pony Express PSA, in the fourth quarter of 2013 PXP paid us approximately $83.0 million representing the net book value of the Pony Express Assets at the time of sale, and is obligated to reimburse us for (i) costs associated with the Pony Express Abandonment, currently estimated to be $10.0 million, (ii) costs to construct the Replacement Gas Facilities, currently estimated to be approximately $69.2 million, and (iii) costs incurred in obtaining gas pipeline transportation services for existing customers from other interstate pipelines for a minimum period of 5 years, and up to 10 years, currently estimated to be approximately $13.5 million per year. We used all proceeds from the upfront payment of the actual net book value of the Pony Express Assets to pay down borrowings under our revolving credit facility.

Other Transactions

Tallgrass Management, LLC, an affiliate of our general partner, has two employees who are immediate family members of executive officers of our general partner. Jason Dehaemers, a director of corporate development, is the son of David Dehaemers, Jr., the President and Chief Executive Officer of our general partner and a member of our general partner s board of directors. For 2013, he received cash compensation of

$235,000, standard employee benefits of approximately $14,400, and the award of 20,000 unvested EPUs on terms consistent with all eligible employees having a weighted average grant date fair value of $17.49 per EPU. Zach Rider, a financial analyst, is the son of George Rider, the Executive Vice President, General Counsel and Secretary of our general partner. For 2013, he received cash compensation of $70,200, standard employee benefits of approximately $11,250, and the award of 5,000 unvested EPUs on terms consistent with all eligible employees having a weighted average grant date fair value of $17.49 per EPU.

Procedures for Review, Approval or Ratification of Transactions with Related Persons

The board of directors of our general partner has adopted a code of business conduct and ethics. Among other things, it provides that the board of directors of our general partner or its authorized committee will periodically review all related person transactions that are required to be disclosed under SEC rules and, when appropriate, initially authorize or ratify all such transactions. In the event that the board of directors of our general partner or its authorized committee considers ratification of a related person transaction and determines not to so ratify, the code of business conduct and ethics provides that our management will make all reasonable efforts to cancel or annul the transaction.

The code of business conduct and ethics also provides that, in determining whether or not to recommend the initial approval or ratification of a related person transaction, the board of directors of our general partner or its authorized committee should consider all of the relevant facts and circumstances available, including (if applicable) but not limited to: (i) whether there is an appropriate business justification for the transaction; (ii) the benefits that accrue to us as a result of the transaction; (iii) the terms available to unrelated third parties entering into similar transactions; (iv) the impact of the transaction on a director s independence (in the event the related person is a director, an immediate family member of a director or an entity in which a director or an immediate family member of a director is a partner, shareholder, member or executive officer); (v) the availability of other sources for comparable products or services; (vi) whether it is a single transaction or a series of ongoing, related transactions; and (vii) whether entering into the transaction would be consistent with the code of business conduct and ethics.

Director Independence

The information required by Item 407(a) or Regulation S-K is included in Item 10. Directors, Executive Officers and Corporate Governance.

Item 14. Principal Accounting Fees and Services

We have engaged PricewaterhouseCoopers LLP as our independent registered public accounting firm. The following table summarizes fees we were billed by PricewaterhouseCoopers LLP (or included in TD s general and administrative expense allocation to us) for independent auditing, tax and related services for each of the last two fiscal years:

	TEP	TEP	TEP Pre-Predecessor
	Year Ended December 31, 2013	Period from November 13 to December 31, 2012	Period from January 1 to November 12, 2012
	(in thousands)		(in thousands)
Audit fees (1)	$ 1,516	$	$
Audit related fees (2)		630	

Tax fees (3)	210			
Total	$ 1,726	$	630	$

(1) Audit fees represent amounts billed for each of the years presented for professional services rendered in connection with (i) the integrated audit of our annual financial statements and internal control over financial

reporting, (ii) the review of our quarterly financial statements or (iii) those services normally provided in connection with statutory and regulatory filings or engagements including comfort letters, consents and other services related to SEC matters. This information is presented as of the latest practicable date for this Annual Report.

(2) Audit-related fees represent amounts we were billed in each of the years presented for assurance and related services that are reasonably related to the performance of the annual audit or quarterly reviews of our financial statements and are not reported under audit fees.

(3) Tax fees represent amounts we were billed in each of the years presented for professional services rendered in connection with tax compliance, tax advice and tax planning.

All services provided by our independent registered public accountant are subject to pre-approval by the audit committee of our general partner. The audit committee of our general partner is informed of each engagement of the independent registered public accountant to provide services under the policy. The audit committee of our general partner has approved the use of PricewaterhouseCoopers LLP as our independent registered public accounting firm.

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Part IV

Item 15. Exhibits, Financial Statement Schedules

(2) Financial Statements Schedules

All schedules are omitted because the required information is either not present, not present in material amounts or included within the Consolidated Financial Statements.

(3) 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) 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) filed on March 28, 2013).
3.3	Amended and 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) 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).
10.1	Contribution, Conveyance and Assumption Agreement, dated May 17, 2013, by and among Tallgrass Energy Partners, LP, Tallgrass MLP GP, LLC, Tallgrass Development, LP, Tallgrass Development GP, LLC, Tallgrass GP Holdings, LLC, Tallgrass Operations, LLC, Tallgrass Interstate Gas Transmission, LLC, Tallgrass Midstream, LLC and Tallgrass MLP Operations, LLC (incorporated by reference to Exhibit 10.1 to the Partnership s Current Report on Form 8-K filed on May 17, 2013).
10.2	Omnibus Agreement, dated May 17, 2013, by and among Tallgrass Development, LP, Tallgrass Energy Partners, LP, Tallgrass MLP GP, LLC and Tallgrass Development GP, LLC (incorporated by reference to Exhibit 10.2 to the Partnership s Current Report on Form 8-K filed on May 17, 2013).
10.3	Revolving Credit Agreement, dated May 17, 2013, by and among Tallgrass Energy Partners, LP, Barclays Bank PLC, as administrative agent, and a syndicate of lenders named therein (incorporated by reference to Exhibit 10.3 to the Partnership s Current Report on Form 8-K filed on May 17, 2013).
10.4	Tallgrass MLP GP, LLC Long-Term Incentive Plan (incorporated by reference to Exhibit 10.4 to the Partnership s Current Report on Form 8-K filed on May 17, 2013).
10.5	Form of Employee Equity Participation Unit Agreement (incorporated by reference to Exhibit 4.5 to the Partnership s Registration Statement on Form S-8 filed on June 28, 2013).
10.6	Amended and Restated Employment Agreement, dated May 17, 2013, by and among Tallgrass Management, LLC, Tallgrass Development GP, LLC, Tallgrass GP Holdings, LLC, Tallgrass MLP GP, LLC and David G. Dehaemers, Jr. (incorporated by reference to Exhibit 10.5 to the Partnership s Registration Statement on Form S-1/A (File No. 333-187595) filed on April 18, 2013).

10.7	Purchase and Sale Agreement, dated August 1, 2012, between Kinder Morgan Interstate Gas Transmission LLC and Kinder Morgan Pony Express Pipeline LLC (incorporated by reference to Exhibit 10.7 to the Partnership s Registration Statement on Form S-1/A (File No. 333-187595) filed on April 8, 2013).
21.1*	List of Subsidiaries of Tallgrass Energy Partners, LP.
23.1*	Consent of PricewaterhouseCoopers LLP.

Exhibit No.	Description
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
 - Management contract or compensatory plan or arrangement required to be filed as an exhibit to this 10-K pursuant to Item 15(b).

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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

By: Tallgrass MLP GP, LLC, its general partner

Date: March 11, 2014

By: /s/ Gary J. Brauchle
Gary J. Brauchle
Executive Vice President, Chief Financial Officer and Treasurer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Name	*Title*	*Date*
/s/ David G. Dehaemers, Jr. David G. Dehaemers, Jr.	Director, President and Chief Executive Officer (Principal Executive Officer)	March 11, 2014
/s/ Gary J. Brauchle Gary J. Brauchle	Executive Vice President, Chief Financial Officer and Treasurer (Principal Financial and Accounting Officer)	March 11, 2014
/s/ Frank J. Loverro Frank J. Loverro	Director	March 11, 2014
/s/ Stanley de J. Osborne Stanley de J. Osborne	Director	March 11, 2014
/s/ Jeffrey A. Ball Jeffrey A. Ball	Director	March 11, 2014
/s/ John T. Raymond John T. Raymond	Director	March 11, 2014
/s/ William R. Moler William R. Moler	Director	March 11, 2014

/s/ Terrance D. Towner		
Terrance D. Towner	Director	March 11, 2014
/s/ Roy N. Cook		
Roy N. Cook	Director	March 11, 2014